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 **1-40144**

APA CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**86-1430562**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

2000 W. Sam Houston Pkwy. S., Suite 200, Houston, Texas 77042-3643
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code **(713) 296-6000**

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, $0.625 par value	**APA**	**Nasdaq Global Select Market**

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. ☒

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2025	$	6,561,964,169
Number of shares of registrant's common stock outstanding as of January 31, 2026		353,251,476

Documents Incorporated By Reference

Portions of the registrant's definitive proxy statement relating to the registrant's 2026 annual meeting of stockholders are incorporated by reference in Part II and Part III of this Annual Report on Form 10-K.

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FORWARD-LOOKING STATEMENTS AND RISKS

This Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical facts included or incorporated by reference in this Annual Report on Form 10-K, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected revenues, projected costs, and plans and objectives of management for future operations and capital returns framework, are forward-looking statements. Such forward-looking statements are based on the Company's examination of historical operating trends, the information that was used to prepare its estimate of proved reserves as of December 31, 2025, and other data in the Company's possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "could," "expect," "intend," "project," "estimate," "anticipate," "plan," "target," "believe," "continue," "seek," "guidance," "goal," "might," "outlook," "possibly," "potential," "predict," "prospect," "should," "would," or similar terminology or the negative of these terms, but the absence of these words does not mean that a statement is not forward looking. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable under the circumstances, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, its assumptions about:

- changes in local, regional, national, and international economic conditions;
- the market prices of oil, natural gas, natural gas liquids (NGLs), and other products or services, including the prices received for natural gas purchased from third parties to sell and deliver to a U.S. LNG export facility;
- the Company's commodity hedging arrangements;
- the supply and demand for oil, natural gas, NGLs, and other products or services;
- production and reserve levels;
- drilling risks;
- economic and competitive conditions, including market and macro-economic disruptions resulting from trade tensions between the U.S. and other countries, armed conflicts, and actions taken by foreign oil and gas producing nations, including the Organization of the Petroleum Exporting Countries (OPEC) and non-OPEC members that participate in OPEC initiatives (OPEC+);
- the availability of capital resources;
- capital expenditures and other contractual obligations;
- asset retirement and decommissioning obligations, including changes to applicable regulatory and industry standards, the timing of related activities, and potential obligations to decommission previously owned assets;
- currency exchange rates;
- weather conditions;
- inflation rates;
- the impact of changes in tax legislation;
- the impact of international or domestic trade policy changes, including tariffs, import/export controls, and sanctions;
- the availability of goods and services;
- the impact of political pressure and the influence of environmental groups and other stakeholders on decisions and policies related to the industries in which the Company and its affiliates operate;
- legislative, regulatory, or policy changes, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring, or water disposal;
- liabilities, injunctive relief, corrective actions, or other adverse outcomes resulting from pending or future litigation, governmental investigations, regulatory proceedings, or alleged violations of laws, regulations, permits, or contractual obligations;
- market-related risks, such as general credit, liquidity, and interest-rate risks;
- the ability to retain and hire key personnel;
- property acquisitions or divestitures;

- the integration of acquisitions;
- other factors disclosed under Items 1 and 2—Business and Properties—Estimated Proved Reserves and Future Net Cash Flows, Item 1A—Risk Factors, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations, Item 7A—Quantitative and Qualitative Disclosures About Market Risk and elsewhere in this Annual Report on Form 10-K.

Other factors or events that could cause the Company's actual results to differ materially from the Company's expectations may emerge from time to time, and it is not possible for the Company to predict all such factors or events. All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by these cautionary statements. All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. Except as required by law, the Company disclaims any obligation to update or revise these statements, whether based on changes in internal estimates or expectations, new information, future developments, or otherwise.

DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this Annual Report on Form 10-K. As used herein:

"3-D" means three-dimensional.

"4-D" means four-dimensional.

"b/d" means barrels of oil or NGLs per day.

"bbl" or "bbls" means barrel or barrels of oil or NGLs.

"bcf" means billion cubic feet of natural gas.

"bcf/d" means one bcf per day.

"boe" means barrel of oil equivalent, determined by using the ratio of one barrel of oil or NGLs to six Mcf of gas.

"boe/d" means boe per day.

"Btu" means a British thermal unit, a measure of heating value.

"liquids" means oil and NGLs.

"LNG" means liquefied natural gas.

"Mb/d" means Mbbls per day.

"Mbbls" means thousand barrels of oil or NGLs.

"Mboe" means thousand boe.

"Mboe/d" means Mboe per day.

"Mcf" means thousand cubic feet of natural gas.

"Mcf/d" means Mcf per day.

"MMbbls" means million barrels of oil or NGLs.

"MMboe" means million boe.

"MMBtu" means million Btu.

"MMBtu/d" means MMBtu per day.

"MMcf" means million cubic feet of natural gas.

"MMcf/d" means MMcf per day.

"NGL" or "NGLs" means natural gas liquids, which are expressed in barrels.

"NYMEX" means New York Mercantile Exchange.

"oil" includes crude oil and condensate.

"PUD" means proved undeveloped.

"SEC" means the United States Securities and Exchange Commission.

"Tcf" means trillion cubic feet of natural gas.

"U.K." means United Kingdom.

"U.S." means United States.

With respect to information relating to the Company's working interest in wells or acreage, "net" oil and gas wells or acreage is determined by multiplying gross wells or acreage by the Company's working interest therein. Unless otherwise specified, all references to wells and acres are gross.

References to "APA," the "Company," "we," "us," and "our" refer to APA Corporation and its consolidated subsidiaries, including Apache Corporation, unless otherwise specifically stated. References to "Apache" refer to Apache Corporation, the Company's wholly owned subsidiary, and its consolidated subsidiaries, unless otherwise specifically stated.

PART I

ITEMS 1 and 2. ***BUSINESS AND PROPERTIES***

GENERAL

APA Corporation (APA or the Company) is an independent energy company that owns subsidiaries that explore for, develop, and produce crude oil, natural gas, and NGLs. The Company's business has oil and gas operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea (North Sea). APA also has active development, exploration, and appraisal operations ongoing in Suriname, as well as exploration interests in Uruguay, Alaska, and other international locations that may, over time, result in reportable discoveries and development opportunities. As a holding company, APA Corporation's primary assets are its ownership interests in its consolidated subsidiaries.

The Company makes available, free of charge on its website at www.apacorp.com, its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after they are filed with, or furnished to, the SEC. The Company's filings are also available at www.sec.gov. Information contained on, or accessible through, the Company's website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

BUSINESS STRATEGY

APA maintains a diversified asset portfolio, including conventional and unconventional, onshore and offshore, oil and natural gas exploration and production interests, while offering global exploration opportunities. In the U.S., operations are primarily focused in the Permian Basin of West Texas. Internationally, the Company has conventional onshore assets in Egypt's Western Desert, offshore assets on the U.K.'s Continental Shelf, and is currently progressing with an oil field development offshore Suriname targeting first production in 2028.

APA believes energy underpins global progress, and the Company wants to be a part of the solution as society works to meet growing global demand for reliable and affordable energy. Uncertainties in the global supply chain and financial markets impact oil supply and demand and contribute to commodity price volatility. These uncertainties include the impacts of ongoing international conflicts, inflation, current and potential tariffs or other trade barriers, global trade policies, and actions taken by foreign oil and gas producing nations, including OPEC+. Despite these uncertainties, the Company is focused on its longer-term objectives: (1) to remain committed to providing affordable, reliable, and responsibly produced energy; (2) to deliver top operational performance across safety, environmental responsibility, execution, and risk management measures; (3) to maintain financial discipline by managing costs, protecting the balance sheet to underpin the generation of cash flow in excess of its upstream exploration, appraisal, and development capital program that can be directed to debt reduction, share repurchases, and other return of capital to its shareholders; and (4) to build and grow a diverse and balanced high-quality portfolio with scale through acquisitions, exploration, and organic opportunities.

The Company closely monitors hydrocarbon pricing fundamentals to reallocate capital as part of its ongoing planning process. APA's diversified asset portfolio and operational flexibility provide the Company the ability to timely respond to near-term price volatility and effectively manage its investment programs.

Rigorous management of the Company's asset portfolio plays a key role in optimizing shareholder value over the long term. Over the past several years, APA has entered into a series of transactions that have upgraded its portfolio of assets, enhanced its capital allocation process to further optimize investment returns, and increased focus on internally generated exploration with full-cycle, returns-focused growth. These transactions include:

- On April 1, 2024, APA completed its acquisition of Callon Petroleum Company (Callon) in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's debt. The acquired assets included approximately 120,000 net acres in the Delaware Basin and 25,000 net acres in the Midland Basin. The Company was able to quickly advance on opportunities to reduce costs, improve capital efficiencies, leverage economies of scale, and expand the development inventory that formed the basis of the transaction value. This transaction complemented and enhanced APA's asset base in the Permian Basin and its inventory of high quality, short-cycle opportunities.

- Throughout the remainder of 2024, APA closed on a series of transactions to sell non-core producing properties in the Permian Basin, East Texas Austin Chalk, and Eagle Ford plays, and non-core mineral and royalty interests in the Permian Basin. Proceeds of approximately $1.6 billion from these transactions were used primarily to reduce debt.

- During 2025, APA completed the sale of certain non-core assets and leasehold in the Permian Basin, reflecting a full exit from New Mexico. Final proceeds of $571 million were primarily used for debt reduction. Combined with the Callon transaction, the Company believes its acreage position and drilling opportunities are better streamlined for longer-term growth.

For a more in-depth discussion of the Company's 2025 results, divestitures, strategy, and its capital resources and liquidity, please see Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report on Form 10-K.

BUSINESS OVERVIEW

The following business overview further describes the Company's exploration and production operations and activities by geographic region.

Operating Areas

APA's business has oil and gas operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea. APA also has active development, exploration, and appraisal operations in Suriname, as well as exploration interests in Uruguay, Alaska, and other international locations that may, over time, result in reportable discoveries and development opportunities.

The following table sets out a brief comparative summary of certain key 2025 data for each of the Company's operating areas. Additional data and discussion are provided in Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations of this Annual Report on Form 10-K.

	Production	Percentage of Total Production	Production Revenue	Year-End Estimated Proved Reserves	Percentage of Total Estimated Proved Reserves	Gross Wells Drilled	Gross Productive Wells Drilled
	(In MMboe)		(In millions)	(In MMboe)			
United States	105.0	62 %	$ 3,819	781	74 %	197	197
Egypt[1]	53.3	31 %	2,637	176	17 %	98	71
North Sea[2]	11.2	7 %	773	25	2 %	—	—
Suriname	—	— %	—	74	7 %	—	—
Total	169.5	100 %	$ 7,229	1,056	100 %	295	268

(1) The Company's operations in Egypt, excluding the impacts of a one-third noncontrolling interest, contributed 23 percent of 2025 production and accounted for 12 percent of year-end 2025 estimated proved reserves.

(2) Sales volumes from the Company's North Sea assets for 2025 were 11.4 MMboe. Sales volumes may vary from production volumes as a result of the timing of liftings.

United States

In 2025, the Company's U.S. oil and gas operations contributed approximately 62 percent of production, 53 percent of oil and gas revenues, and 74 percent of estimated year-end proved reserves. APA has access to significant liquid hydrocarbons across its 2.6 million gross acres (1.3 million net acres) in the U.S..

The Company's U.S. producing assets are primarily located in the Permian Basin in West Texas, including the Midland and Delaware sub-basins. Examples of shale plays being developed within these sub-basins include the Spraberry, Bone Spring, Wolfcamp, Barnett, and Woodford. The Company operates approximately 4,000 gross oil and gas wells across its acreage, with additional interests in approximately 700 non-operated wells. APA also has legacy operations located offshore in the Gulf of America. Highlights of the Company's operations in the U.S. include:

- *Permian Basin* The Permian Basin is a foundational asset for APA, providing the Company's largest source of production and cash flow. Over the past two years, the Company has progressed on high-grading its scale of operations and localized knowledge through the Callon acquisition and exit from non-core holdings in the conventional Central Basin Platform and positions in New Mexico. This concentrates APA's position in a few key areas that enable economies of scale in operations and provides significant flexibility in pacing of developmental and appraisal activity.

  In addition, the Company has been able to make significant strides in reducing drilling, completions, and equipping and facility costs by leveraging these synergies while refining its development approach to its asset base. Improvements in its cost structure has enabled the Company to drill more wells on tighter and denser spacing and to moderate completion intensity.

  Key assets in the Permian Basin include:

  - *Midland Basin* APA holds approximately 406,000 gross acres (288,000 net acres) in the Midland Basin in West Texas. During 2025, the Company primarily targeted oil plays in the Spraberry and Wolfcamp shale formations, drilling 106 gross development wells in this basin with a 100 percent success rate.

- *Delaware Basin* APA holds approximately 217,000 gross acres (166,000 net acres) in the Delaware Basin of West Texas. During 2025, the Company drilled 84 gross development wells in this basin with a 100 percent success rate, primarily targeting the Bone Spring and Wolfcamp formations. Also during 2025, the Company divested certain of its non-core producing properties located in New Mexico.

- *Legacy Assets* APA holds approximately 1.7 million gross acres (0.7 million net acres) in legacy properties, of which approximately 513,000 gross acres are in the offshore waters of the Gulf of America. Consistent with the Company's broader portfolio management efforts, certain non-strategic leasehold positions on its legacy acreage holdings provide additional monetization opportunities that continue to be evaluated. During 2025, the Company participated in the drilling of 7 gross development wells in this area with a 100 percent success rate.
- *New Venture Assets* APA holds approximately 325,000 gross acres (163,000 net acres) of undeveloped acreage on the North Slope of Alaska. During 2025, the Company and its partners announced preliminary results of an exploratory well in Alaska, confirming the successful discovery of a reservoir. A successful flow test of the well was announced in 2025, with the well averaging 2,700 b/d during the final flow period. The Company continues to evaluate data from the well, and further appraisal drilling will determine the ultimate size of the discovery.

The Company is committed to maintaining a safe and efficient level of activity as part of its planned capital investment program. For 2026, the Company will continue to budget its capital program at levels to fund activity necessary to offset inherent declines in production and proved oil and natural gas reserves, subject to prevailing commodity prices. Future rig activity levels and drilling targets will be dependent on the success of the Company's drilling program and its ability to add reserves economically.

U.S. Marketing The Company sells its U.S. natural gas production at liquid index sales points within the U.S., at either monthly or daily index-based prices. The tenor of the Company's sales contracts span from daily to multi-year transactions. Natural gas is sold to a variety of customers that include local distribution, utility, and midstream companies, as well as end-users, marketers, and integrated major oil companies. APA strives to maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk.

APA primarily markets its U.S. crude oil production to integrated major oil companies, marketing and transportation companies, and refiners based on West Texas Intermediate (WTI) pricing indices (e.g., WTI Houston, West Texas Sour (WTS), WTI Midland, or West Texas Light (WTL) Midland) and some predominately Brent related international pricing indices, adjusted for quality, transportation, and a market-reflective differential. The Company's objective is to maximize the value of crude oil sold by identifying the best markets and most economical transportation routes available to move the product. Sales contracts are generally 30-day evergreen contracts that renew automatically until canceled by either party. These contracts provide for sales that are priced daily at prevailing market prices. Also, from time to time, the Company will enter into physical term sales contracts. These term contracts typically have a firm transportation commitment and often provide an opportunity for higher than prevailing market prices.

APA's U.S. NGL production is sold under contracts with prices based on Gulf Coast supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

U.S. Delivery Commitments The Company has long-term delivery commitments for natural gas and crude oil that require APA to deliver an average of 152 Bcf of natural gas per year for the period from 2026 through 2029, an average of 49 Bcf of natural gas per year for the period from 2030 through 2037, an average of 1.8 MMbbls of crude oil per year for the period from 2026 through 2028, and de minimis crude oil volumes in the year 2029, in each case, at variable, domestic and/or international, market-based pricing.

In order to satisfy certain delivery commitments, the Company purchases third-party natural gas and crude oil to sell and deliver under existing pipeline agreements and sales contracts. APA may also enter into contractual arrangements to reduce its delivery commitments. The Company has not experienced any significant constraints in satisfying the committed quantities required by its delivery commitments.

For more information regarding the Company's commitments, please see Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Contractual Obligations of this Annual Report on Form 10-K.

International

APA has two international locations with ongoing production operations:

- Egypt, which includes onshore conventional assets located in Egypt's Western Desert; and
- the North Sea, which includes offshore assets based in the U.K.

Egypt APA has decades of exploration, development, and operations experience in Egypt and is the largest acreage holder in Egypt's Western Desert. At year-end 2025, the Company held 7.5 million gross acres in six separate concessions. The Company's acreage is primarily held under one merged concession agreement (MCA) that resulted from the ratification of a MCA in 2021 with the Government of Egypt and EGPC. The MCA consolidated 98 percent of gross acreage and 90 percent of gross production under one concession agreement and refreshed the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool to provide improved access to cost recovery, a fixed 40 percent cost recovery limit, and a fixed profit-sharing rate of 30 percent for all the Company's production covered under the concession. Approximately 76 percent of the Company's gross acreage in Egypt is undeveloped, providing APA with considerable exploration and development opportunities for the future.

APA's Egypt operations are conducted pursuant to production-sharing contracts (PSCs). Under the terms of the Company's PSCs, the Company is the contractor partner (Contractor) with EGPC and bears the risk and cost of exploration, development, and production activities. In return, if exploration is successful, the Contractor receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of production after cost recovery. Additionally, the Contractor's income taxes, which remain the liability of the Contractor under domestic law, are paid by EGPC on behalf of the Contractor out of EGPC's production entitlement. Income taxes paid to the Arab Republic of Egypt on behalf of the Contractor are recognized as oil and gas sales revenue and income tax expense and are reflected as production and estimated reserves. Because Contractor cost recovery entitlement and income taxes paid on its behalf are determined as a monetary amount, the quantities of production entitlement and estimated reserves attributable to these monetary amounts will fluctuate with commodity prices. In addition, because the Contractor income taxes are paid by EGPC, the amount of the income tax has no economic impact on the Company's Egypt operations despite impacting the Company's production and reserves.

The APA subsidiary that is the sole Contractor under the MCA is owned by an APA-operated joint venture owned two-thirds by the Company and one-third by Sinopec International Petroleum Exploration and Production Corporation (Sinopec).

The Company's estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country's share of reserves. Through the joint venture, Sinopec holds a one-third minority participation interest in the Company's oil and gas operations in Egypt. The Company's Egypt assets, including the one-third noncontrolling interest, contributed 31 percent of 2025 production and 17 percent of 2025 year-end estimated proved reserves. Excluding the impacts of the noncontrolling interest, Egypt contributed 23 percent of 2025 production and 12 percent of 2025 year-end estimated proved reserves.

In 2025, the Company drilled 45 gross development and 53 gross exploration wells in Egypt. A key component of the Company's success has been the ability to acquire and evaluate 3-D seismic surveys that enable the Company's technical teams to consistently high-grade existing prospects and identify new targets across multiple pay horizons in the Cretaceous, Jurassic, and deeper Paleozoic formations. The Company has completed seismic surveys covering three million acres, which has led to recent discoveries that build and enhance the Company's drilling inventory in Egypt. The Company will continue to focus on driving efficiencies and managing costs under the MCA.

During 2025, the Government of Egypt awarded the Company an additional two million net exploration acres in the Western Desert. This new acreage expands on the Company's existing position in the country. In addition to a signature bonus of $25 million, the Company has committed to a drilling program on the acreage that the Company believes it will be able to meet in the normal course of operations.

North Sea The Company has interests in approximately 176,000 gross acres in the U.K. North Sea. These assets contributed 7 percent of the Company's 2025 production and approximately 2 percent of year-end 2025 estimated proved reserves.

The Company entered the North Sea in 2003 after acquiring an approximate 97 percent working interest in the Forties field (Forties). In 2011, the Company acquired Mobil North Sea Limited, which included operated interests in the Beryl, Ness, Nevis, Nevis South, Skene, and Buckland fields and a non-operated interest in the Maclure field. The Company also has a non-operated interest in the Nelson field acquired in 2011. In 2023, the Company suspended all new drilling activity in the North Sea. During 2024, the Company performed an economic assessment of its North Sea assets in light of several new regulatory guidelines and obligations surrounding significant tax levies and modernization of aging infrastructure. The Company determined that expected returns did not economically support making investments required under the combined impact of the regulations and expects to cease production at its facilities in the North Sea prior to 2030. The Company's investment program in the North Sea is now directed toward asset safety and integrity.

International Marketing In Egypt, substantially all of the Company's 2025 natural gas production is sold to EGPC pursuant to a gas sales agreement that establishes pricing based on a minimum realized price of $2.65 per MMBtu, with the potential for higher pricing on incremental volumes when pre-determined production thresholds are met. The gas sales agreement, which was effective beginning January 2025, creates the potential for significant new drilling inventory with returns on par with oil. In the periods prior to the current agreement, the natural gas production in Egypt was primarily sold to EGPC at an industry-pricing formula of $2.65 per MMBtu. Crude oil production is sold to third parties in the export market or to EGPC when called upon to supply domestic demand. Oil production sold to third parties is sold and exported from one of two terminals on the northern coast of Egypt. Oil production sold to EGPC is sold at prices related to the export market.

The Company's North Sea crude oil production is sold under term, entitlement volume contracts and spot variable volume contracts with a market-based index price plus a differential to capture the higher market value under each type of arrangement. Natural gas from the Beryl field is processed through the Scottish Area Gas Evacuation (SAGE) gas plant, operated by Ancala Midstream Acquisitions Limited. Natural gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The condensate mix from the SAGE plant is processed further downstream. The split streams of propane, butane, and condensate are sold separately on a monthly entitlement basis at the Braefoot Bay terminal using index pricing less transportation.

Other International

New Ventures APA's international New Ventures acreage provides exposure to new growth opportunities outside of the Company's traditional core areas and provides higher-risk, higher-reward exploration opportunities located in frontier basins as well as new plays in more mature basins.

The Company has a joint venture agreement with TotalEnergies (formerly Total S.A.) to explore and develop Block 58 offshore Suriname. The Company holds a 50 percent working interest in exploration activities in Block 58, which comprises approximately 1.4 million gross acres in water depths ranging from less than 100 meters to more than 2,100 meters. TotalEnergies holds a 50 percent working interest in exploration activities in Block 58 as the operator. Key terms of the joint venture agreement provide for TotalEnergies to pay 50 percent of all exploration activities and a proportionately larger share of appraisal and development costs, which would be recoverable through hydrocarbon participation. For the first $10 billion of gross capital expenditures, TotalEnergies pays 87.5 percent, and the Company pays 12.5 percent; for the next $5 billion in gross expenditures, TotalEnergies pays 75 percent and the Company pays 25 percent; and for all gross expenditures above $15 billion, TotalEnergies pays 62.5 percent and the Company pays 37.5 percent. The Company will also receive various other forms of consideration, including a $75 million cash payment upon achieving first oil production and future contingent royalty payments from successful joint development projects.

In October 2024, the Company announced that its subsidiary reached a positive final investment decision for the first oil development, named GranMorgu, in Block 58 offshore Suriname. This development will include production from the Krabdagu and Sapakara oil discoveries. These fields, located in water depths between 100 and 1,000 meters, will be produced through a system of subsea wells connected to a floating production, storage and offloading (FPSO) unit located 150 km off the Suriname coast, with an oil production capacity of 220,000 b/d. The GranMorgu FPSO unit is designed to accommodate future tie-back opportunities that would extend its four-year production plateau and will feature technology that minimizes greenhouse gas emissions. Total investment is estimated at $10.5 billion, with APA's share of the investment subject to the existing joint venture agreement with TotalEnergies to carry a portion of Apache's appraisal and development capital. Under the terms of the Block 58 PSCs, Staatsolie exercised its right to participate in the GranMorgu development and production for a 20 percent share. First oil is anticipated in 2028.

The Company is also the operator of Block 53 offshore Suriname and holds a 45 percent working interest in the block. The Company, through an extension granted in 2023, holds approximately 13,000 net undeveloped acres for its operated Baja discovery area. Evaluation of the area is ongoing.

During 2023, the Company signed a production-sharing contract for Block 6 offshore Uruguay covering approximately four million undeveloped acres, where it has an obligation to drill one exploration well. In February 2024, the Company also signed a production-sharing contract for Block 4 offshore Uruguay, covering approximately 1.2 million net undeveloped acres. The Company holds a 50 percent working interest in the project and is the operator.

The Company continues to assess, contract, and potentially explore undeveloped acreage positions in other international locations.

Drilling Statistics

Worldwide in 2025, APA drilled or participated in drilling 295 gross wells, with 268 wells (91 percent) completed as producers. Historically, APA's drilling activities in the U.S. have generally concentrated on exploitation and extension of existing producing fields rather than exploration. As a general matter, the Company's operations outside of the U.S. focus on a mix of exploration and development wells. In addition to wells completed during the year, at year-end 2025, a number of wells had not yet reached completion: 103 gross (97.8 net) in the U.S., 25 gross (25.0 net) in Egypt.

The following table shows the results of the oil and gas wells drilled and completed for each of the last three fiscal years:

	Net Exploratory			Net Development			Total Net Wells		
	Productive	Dry	Total	Productive	Dry [1]	Total	Productive	Dry	Total
2025									
United States	—	—	—	146.5	—	146.5	146.5	—	146.5
Egypt	27.5	25.0	52.5	42.3	2.0	44.3	69.8	27.0	96.8
Total	27.5	25.0	52.5	188.8	2.0	190.8	216.3	27.0	243.3
2024									
United States	—	—	—	152.7	—	152.7	152.7	—	152.7
Egypt	16.0	20.0	36.0	45.5	2.0	47.5	61.5	22.0	83.5
Total	16.0	20.0	36.0	198.2	2.0	200.2	214.2	22.0	236.2
2023									
United States	—	—	—	78.4	—	78.4	78.4	—	78.4
Egypt	24.0	24.0	48.0	66.1	7.7	73.8	90.1	31.7	121.8
North Sea	1.2	—	1.2	—	—	—	1.2	—	1.2
Other International	—	0.3	0.3	—	—	—	—	0.3	0.3
Total	25.2	24.3	49.5	144.5	7.7	152.2	169.7	32.0	201.7

(1) No proved undeveloped reserves were included in reserves as of year-end 2024 for the 2.0 net dry development wells drilled in 2025. No proved undeveloped reserves were included in reserves as of year-end 2023 for the 2.0 net dry development wells drilled in 2024.

Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which the Company had an interest as of December 31, 2025, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	3,311	2,514	684	578	3,995	3,092
Egypt	921	894	110	108	1,031	1,002
North Sea	125	85	11	7	136	92
Total	4,357	3,493	805	693	5,162	4,186
Domestic	3,311	2,514	684	578	3,995	3,092
Foreign	1,046	979	121	115	1,167	1,094
Total	4,357	3,493	805	693	5,162	4,186

Production, Pricing, and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil, NGL, and gas production volumes, average lease operating costs per boe (including transportation costs but excluding severance and other taxes), and average sales prices for each of the countries where the Company has operations:

	Production				Average Sales Price		
Year Ended December 31,	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Average Lease Operating Cost per Boe	Oil (Per bbl)	NGL (Per bbl)	Gas (Per Mcf)
2025							
United States	45.8	27.8	187.8	$ 10.19	$ 65.71	$ 22.13	$ 1.02
Egypt[1]	32.0	—	128.1	8.83	67.97	—	3.59
North Sea[2]	8.8	0.5	11.4	34.03	69.31	43.59	12.03
Total	86.6	28.3	327.3	11.36	66.92	22.71	2.36
2024							
United States	47.1	27.0	177.0	$ 11.33	$ 75.92	$ 22.83	$ 0.71
Egypt[1]	32.6	—	106.5	9.70	80.41	—	2.94
North Sea[2]	9.6	0.4	14.6	37.02	80.74	47.59	10.84
Total	89.3	27.4	298.1	12.75	78.08	23.37	1.97
2023							
United States	28.8	23.0	165.1	$ 10.62	$ 77.84	$ 20.85	$ 1.80
Egypt[1]	32.5	—	118.9	9.70	82.47	—	2.91
North Sea[2]	12.7	0.4	18.3	25.34	82.75	47.77	13.02
Total	74.0	23.4	302.3	11.95	80.72	21.54	2.91

(1) Includes production volumes attributable to a one-third noncontrolling interest in Egypt.

(2) Sales volumes from the Company's North Sea assets for 2025, 2024, and 2023 were 11.4 MMboe, 12.4 MMboe, and 16.6 MMboe, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings.

Gross and Net Undeveloped and Developed Acreage

The following table summarizes the Company's gross and net acreage position by geographic area as of December 31, 2025:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(In thousands)			
United States	2,075	955	564	392
Egypt	5,737	5,737	1,769	1,721
North Sea	17	12	159	123
Suriname	1,470	734	—	—
Other International	6,548	5,312	—	—
Total	15,847	12,750	2,492	2,236

As of December 31, 2025, the Company held approximately 5,000 net undeveloped acres in the U.S. that are scheduled to expire by year-end 2026 if production is not established or the Company takes no action to extend the terms. Nearly all of the Company's U.S. acreage expiring in 2026 is in the Delaware Basin. The Company also held approximately 1,000 and 7,000 net undeveloped acres on its U.S. onshore acreage set to expire by year-end 2027 and 2028, respectively. As of December 31, 2025, approximately 81 percent of the U.S. net undeveloped acreage was held by production or owned as undeveloped mineral rights. The Company also has approximately 84,000 and 22,000 net undeveloped acres in Alaska set to expire by year-end 2027 and 2028, respectively, if no extension is granted.

During 2025, the Government of Egypt awarded the Company an additional two million net undeveloped exploration acres in the Western Desert for a term of five years, expanding on the Company's existing position in Egypt. The Company also holds undeveloped exploration acreage that was consolidated and extended in 2021 following ratification of the MCA with EGPC. The merged exploration acreage is scheduled to expire in 2026. The Company intends to pursue extensions of this acreage and may seek access to additional concession areas where it believes exploration potential exists. However, there can be no assurance that any such extensions or new access rights will be obtained on commercially acceptable terms, or at all, as these actions are subject to governmental approvals. No oil and gas reserves were recorded on undeveloped acreage set to expire.

The Company held approximately six million net undeveloped acres as of December 31, 2025, in other international locations. Exploration interests include Block 53 and Block 58 offshore Suriname and Block 4 and Block 6 offshore Uruguay. The Company continues to actively evaluate and analyze several discoveries on its Block 58 offshore Suriname exploration acreage with its operator partner, TotalEnergies. Approximately 720,000 net undeveloped acres in Block 58 have a current expiration date of June 2031 with an option to extend further.

The Company continues to assess, contract, and potentially explore undeveloped acreage positions in other international locations.

Estimated Proved Reserves and Future Net Cash Flows

Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and NGLs, 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. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods. The Company reports all estimated proved reserves held under production-sharing arrangements utilizing the "economic interest" method, which excludes the host country's share of reserves.

Estimated reserves that can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project or the operation of an active, improved recovery program using reliable technology establishes the reasonable certainty for the engineering analysis on which the project or program is based. Economically producible means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating its proved reserves, APA uses several different traditional methods that can be classified in three general categories: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy with similar properties. The Company will, at times, utilize additional technical analysis, such as computer reservoir models, petrophysical techniques, and proprietary 3-D seismic interpretation methods, to provide additional support for more complex reservoirs. Information from this additional analysis is combined with traditional methods outlined above to enhance the certainty of the Company's reserve estimates.

Proved undeveloped reserves include those 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. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time period.

The following table shows proved oil, NGL, and gas reserves as of December 31, 2025, based on average commodity prices in effect on the first day of each month in 2025, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. The total column of this table shows reserves on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a ratio of 6 Mcf to 1 bbl. This ratio is not reflective of the current price ratio between the two products.

	Oil (MMbbls)	NGL (MMbbls)	Gas (Bcf)	Total (MMboe)
Proved Developed:				
United States	182	181	1,095	545
Egypt[1]	102	—	371	164
North Sea	22	1	13	25
Total	306	182	1,479	734
Proved Undeveloped:				
United States	121	58	338	235
Egypt[1]	8	—	28	13
Suriname	74	—	—	74
Total	203	58	366	322
Total Proved	509	240	1,845	1,056

(1) Includes total proved developed and total proved undeveloped reserves of 55 MMboe and 4 MMboe, respectively, attributable to a one-third noncontrolling interest in Egypt.

As of December 31, 2025, the Company had total estimated proved reserves of 509 MMbbls of crude oil, 240 MMbbls of NGLs, and 1.8 Tcf of natural gas. Combined, these total estimated proved reserves are the volume equivalent of 1.1 billion boe, of which liquids represent approximately 71 percent. As of December 31, 2025, the Company's proved developed reserves totaled 734 MMboe and estimated proved undeveloped (PUD) reserves totaled 322 MMboe, or approximately 30 percent of worldwide total proved reserves. APA has elected not to disclose probable or possible reserves in this filing. The Company had one field that contained 15 percent or more of its total proved reserves for the year ended December 31, 2025. The Company had no fields that contained 15 percent or more of its total proved reserves for the years ended December 31, 2024 and 2023.

During 2025, the Company added approximately 100 MMboe from extensions, discoveries, and other additions. The Company recorded 72 MMboe of exploration and development adds in the U.S., derived from drilling activity in the Permian Basin primarily targeting the Spraberry, Bone Spring, and Wolfcamp producing horizons. The Company's Egypt operations contributed 28 MMboe of exploration and development adds from onshore exploration and appraisal.

The Company realized combined upward revision of previously estimated reserves of 175 MMboe. Upward revisions related to pricing and interest totaled 37 MMboe, driven primarily by an increase in Permian Basin gas pricing. Engineering and well performance adjustments totaled 138 MMboe in the U.S. and Egypt. Upward revisions of 100 MMboe in the U.S. is related to changes to development plans and updates due to reservoir performance. Egypt realized positive revisions of 38 MMboe from gas infrastructure optimization and improved recovery projects.

Divestitures during 2025 of non-core producing properties in the U.S. reduced estimated proved reserves by approximately 19 MMboe.

The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2025, 2024, and 2023, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 16—Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K. Estimated future net cash flows were calculated using a discount rate of 10 percent per annum, end of period costs, and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

Proved Undeveloped Reserves

The Company's total estimated PUD reserves of 322 MMboe as of December 31, 2025, increased by 22 MMboe from 300 MMboe of PUD reserves reported at year-end 2024. During 2025, the Company converted 76 MMboe of PUD reserves to proved developed reserves through development drilling activity. In the U.S., the Company converted 66 MMboe, with the remaining 10 MMboe in its international areas. The Company disposed of 2 MMboe related to PUD reserves divested during 2025. The Company added 62 MMboe of new PUD reserves through extensions. The Company also revised PUD reserves upward 41 MMboe as a result of updates to field development plans. Other downward revisions include 2 MMboe associated with interest changes and 1 MMboe associated with product prices.

During 2025, a total of approximately $546 million was spent on projects associated with proved undeveloped reserves. A portion of APA's costs incurred each year relate to development projects that will convert undeveloped reserves to proved developed reserves in future years. During 2025, the Company spent approximately $494 million on PUD reserve development activity in the U.S. and $52 million in Egypt. Additionally, the Company spent approximately $256 million in development and facility capital as part of the Suriname development during 2025. As of December 31, 2025, the Company had no material amounts of proved undeveloped reserves scheduled to be developed beyond five years from initial disclosure.

Preparation of Oil and Gas Reserve Information

The Company's reported reserves are reasonably certain estimates which, by their very nature, are subject to revision. These estimates are reviewed throughout the year and revised either upward or downward, as warranted.

APA's proved reserves are estimated at the property level and compiled for reporting purposes by a group of experienced reservoir engineers who interact with engineering and geoscience personnel in each of the Company's operating areas and with accounting and marketing employees to obtain the necessary data for projecting future production, costs, net revenues, and ultimate recoverable reserves. All relevant data is compiled in a computer database application, to which only authorized personnel are given security access rights consistent with their assigned job function. Annually, each property is reviewed in detail by our corporate and operating asset engineers to ensure forecasts of operating expenses, netback prices, production trends, and development timing are reasonable. Reserves are reviewed internally with senior management and presented to APA's Board of Directors in summary form on an annual basis.

APA's Director of Reserves is the person primarily responsible for overseeing the Company's reserves estimation and reporting process. He has a Bachelor of Science degree in Petroleum Engineering and over 40 years of experience in the energy industry. The Director of Reserves reports directly to the Company's Vice President of Assurance.

The estimate of reserves disclosed in this Annual Report on Form 10-K is prepared by the Company's internal staff, and the Company is responsible for the adequacy and accuracy of those estimates. The Company engages Ryder Scott Company, L.P. Petroleum Consultants (Ryder Scott) to conduct a reserves audit, which includes a review of the Company's processes and the reasonableness of the Company's estimates of proved hydrocarbon liquid and gas reserves. The Company selects the properties for review by Ryder Scott based primarily on relative reserve value. The Company also considers other factors such as geographic location, new wells drilled during the year, and reserves volume. During 2025, the properties selected for all countries represented 87 percent of the total future net cash flows discounted at 10 percent. These properties accounted for 80 percent of the value of the Company's domestic proved reserves and 100 percent of the value of the Company's international proved reserves. In addition, all fields containing five percent or more of the Company's total proved reserves volume were included in Ryder Scott's review. The review covered 82 percent of total proved reserves on a boe basis.

The percentages of total estimated proved reserves values, calculated as future net cash flows discounted at 10 percent, and volumes, on a boe basis, covered by Ryder Scott's reviews for the years 2025, 2024, and 2023 were:

	2025	2024	2023
Estimated proved reserves values	87 %	90 %	88 %
Estimated proved reserves volumes:			
United States	80 %	80 %	83 %
Egypt	80 %	80 %	80 %
North Sea	84 %	95 %	90 %
Suriname	100 %	100 %	— %
APA Worldwide	82 %	82 %	83 %

The Company has filed Ryder Scott's independent report as an exhibit to this Annual Report on Form 10-K.

According to Ryder Scott's opinion, based on their review, including the data, technical processes, and interpretations presented by the Company, the overall procedures and methodologies utilized by the Company in determining the proved reserves comply with the current SEC regulations, and the overall proved reserves for the reviewed properties as estimated by the Company are, in aggregate, reasonable within the established audit tolerance guidelines as set forth in the Society of Petroleum Engineers auditing standards.

MAJOR CUSTOMERS

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. During 2025, sales to EGPC in Egypt accounted for approximately 15 percent of the Company's worldwide crude oil, natural gas, and NGLs revenues. During 2024 and 2023, sales to EGPC accounted for approximately 17 percent and 15 percent of the Company's worldwide crude oil, natural gas, and NGLs revenues.

Management does not believe that the loss of any single customer would have a material adverse effect on the results of operations.

HUMAN CAPITAL MANAGEMENT

Human Capital and Employees

APA's ability to execute its strategy depends on attracting, developing, and retaining a skilled workforce. The Company focuses on employee health and safety, total rewards, development opportunities and community partnerships to support employee experience and performance.

As of December 31, 2025, APA employed approximately 1,791 full-time equivalent employees:

	Employees
United States	1,061
United Kingdom	486
Egypt	242
Suriname	—
France	2
Total employees	1,791

Oversight and Management

The Management Development and Compensation (MD&C) Committee and/or the full Board of Directors receive regular reports on human capital matters. The MD&C Committee also oversees compensation programs, leadership development, and succession planning. These activities support APA's core values, which include health and safety, investment in the workforce, environmental responsibility, continuous improvement, and ethical conduct.

Equal Opportunity Employer

APA is an equal opportunity employer and prohibits discrimination and harassment. Personnel actions are administered without regard to race, color, religion, sex, familial status, marital status, sexual orientation, gender identity or expression, pregnancy, age, national origin, disability status, genetic information, protected veteran status, or any other characteristic protected by law.

APA also maintains resources to support an inclusive work environment where employees are valued and able to thrive.

Talent

APA's talent strategy integrates recruitment and development to support organizational capability and leadership development and ingenuity.

Recruitment uses technology and data-driven insights to identify talent globally and uses referrals and feedback to strengthen local sourcing.

APA also engages with educational institutions, industry networks, and professional organizations to access emerging talent and build relationships with industry professionals.

Beyond recruitment, the Company invests in talent development initiatives designed to build capability, strengthen leadership effectiveness, and reinforce a high-performance culture. These initiatives include continuous learning opportunities, skill enhancement programs, mentorship frameworks, and leadership development programs.

In 2025, APA emphasized leadership and culture initiatives. Senior leadership focused on strategic priorities and development of a strong corporate culture that reinforces shared values, collaboration, accountability, and continuous improvement.

Training and Development

Employee development is supported through training, performance management, and continuous feedback using in-person and virtual delivery.

2025 highlights included:

- Technical Excellence Initiative: Launched an initial framework defining technical capability expectations and progression pathways across critical disciplines with broader implementation planned for 2026.
- Individual Development Plan (IDP): Began implementing an IDP framework to identify development priorities, align learning activities with career aspirations, and track progress over time.
- Performance Management: Continued strengthening the program with increased emphasis on ongoing feedback and development conversations.
- Learning access: Expanded on-demand learning through multiple online learning platforms offering technical, leadership, and business acumen content.
- Succession planning: Remained a critical component of APA's talent strategy including identifying key roles, assessing readiness, and targeted development actions.
- Additional development and training opportunities offered during the year included:
    - Third-party online and in-person training programs;
    - Ongoing education for people leaders aligned to leadership competencies;
    - Leadership and personal development coaching by line managers;
    - Annual cybersecurity training;
    - Annual compliance training including antitrust, bribery, corruption, and the APA Code of Conduct; and
    - Mandatory health, safety, and environmental training for field and offshore employees.

Total Rewards

APA's total rewards approach is designed to attract, motivate, and retain top talent by providing a robust compensation and benefits package that includes competitive base salary, industry-leading benefits and performance-driven incentives. To foster a stronger sense of ownership and align the interests of employees and shareholders, annual long-term incentive grants are provided to eligible employees under APA's long-term incentive compensation program. Furthermore, the Company offers comprehensive and locally relevant benefits that cultivate a family-friendly work environment and focus on the overall wellness of the Company's employees. In the U.S. these include, among other benefits:

- Comprehensive health insurance coverage offered to employees working an average of 20 hours or more each week;
- 401(k) plan with up to an 8 percent Company match;
- 6 percent Company contributions to a money purchase retirement plan;
- Company-paid short-term disability that pays a percentage of base pay according to years of service;

- Parental leave for all new parents for birth and adoption;
- Fertility and family building benefits to support the various paths to parenthood;
- Elder care leave to temporarily care for or find permanent care for elder family members;
- Comprehensive mental health offering that includes access to mental health therapists or coaches, a learning platform that offers on-demand and interactive courses on mental health topics, and a library of well-being and self-care resources; and
- Well-being program that encourages healthy habits and promotes physical, financial, social, and emotional well-being through webinars and challenges throughout the year.

Environment, Health and Safety (EH&S)

APA's priority is the health and safety of its workforce. The Company's environmental, health, and safety and operations functions partner to consistently reinforce its core values, standards, and operating practices as well as foster a safety culture that empowers the Company's workforce to stop work if conditions or behaviors are deemed unsafe. APA focuses on incident mitigation, driving safety, and environmental stewardship across its global operations every day, with the help of visible and engaged leadership, by setting clear expectations and making safety personal for all employees and contractors.

Global Primary Workforce Safety Metrics

Total Recordable Incident Rate (TRIR)[(1)]	0.13	35% below target of 0.20
Severe Incident Rate (SIR)[(2)]	0.0	100% below target of 0.010
US Flaring Intensity[(3)]	0.84	16% below target of 1.0

(1) Total Recordable Incident Rate (TRIR): The rate of recordable injuries sustained by employees, contractors, or both that occur per 200,000 hours worked.

(2) Severe Incident Rate (SIR): The rate of incidents resulting in fatal injury, permanent or significant loss or impairment of a body part or organ function, or that otherwise permanently change or disable individuals in their normal life activity, per 200,000 hours worked.

(3) Flaring Intensity: The volume of gas flared per volume of gas produced expressed as a percent.

Community Partnerships

APA is committed to being a responsible partner in the communities where it operates. The Community Partnerships group oversees the Company's global strategic community engagement, including the stewardship of key stakeholder relationships.

APA's global giving strategy is focused on three pillars: Community Well-being, Environmental Stewardship, and Access to Energy, through which the Company creates sustainable and positive impacts. Based on these pillars, APA is committed to addressing acute needs within the local communities where it operates; ensuring that it remains focused on its long-standing legacy and commitment to environmental stewardship and conservation; and supporting communities that lack access to reliable, affordable energy.

- Community Well-being: APA continues to partner with organizations within the communities in which it operates to improve quality of life through access to education and essential medical supplies; development of innovative healthcare technologies and procedures; support for vulnerable populations; response to natural disasters; and support for first responders.
- Environmental Stewardship: In 2025, the Company's environmental stewardship initiatives included grants of more than 16,000 trees to community partners in the U.S. and U.K. through the Apache Corporation Tree Grant Program. The Company also continued its partnership with the Texas Wildlife Association Foundation to support environmental education programs and provided multi-year support to the Pecos Watershed Conservation Initiative, an alliance of seven energy companies, in partnership with the National Fish and Wildlife Foundation, focused on restoring and protecting natural grasslands and habitats within the greater Trans-Pecos region.
- Access to Energy: In 2025, the Company continued to support access to affordable, reliable energy through its partnership with Switch Energy Alliance, a Houston-based nonprofit focused on energy education, workforce development, and informed energy dialogue. The Company's support helped advance Switch Energy Alliance's programming that increases understanding of energy systems, energy access challenges, and the role of diverse energy solutions in supporting economic development and quality of life in energy-impacted communities.

APA also provides employees with volunteer service opportunities in collaboration with its Community Partnerships program. The Company seeks meaningful volunteer opportunities that instill a sense of pride, ownership, and accomplishment for employees in their communities. As community needs change and stakeholder engagement continues, APA continues to adjust its charitable giving program.

OFFICES

The Company's principal executive offices are located at 2000 W. Sam Houston Pkwy. S., Suite 200, Houston, Texas 77042-3643. As of year-end 2025, the Company maintained offices in Midland, Texas; Houston, Texas; Cairo, Egypt; and Aberdeen, Scotland. The Company's primary office space is leased. The current lease on the Company's principal executive offices runs through December 31, 2038, subject to the lessee's option to extend the term by up to 20 years. For information regarding the Company's obligations under its office leases, please see Part II, Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Contractual Obligations and Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

TITLE TO INTERESTS

As is customary in the oil and gas industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time the Company acquires properties. The Company believes that its title to all of the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in the Company's operations. The interests owned by the Company may be subject to one or more royalty, overriding royalty, or other outstanding interests (including disputes related to such interests) customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations, and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as production payments, net profits interests, liens incident to operating agreements and current taxes, development obligations under oil and gas leases, and other encumbrances, easements, and restrictions, none of which detract substantially from the value of the interests or materially interfere with their use in the Company's operations.

ADDITIONAL INFORMATION ABOUT THE COMPANY

Response Plans and Available Resources

The Company's subsidiaries maintain oil spill response plans (the Plans) for their respective offshore operations in the Gulf of America and the North Sea, which ensure rapid and effective responses to spill events that may occur on such entities' operated properties. Emergency preparedness exercises are conducted to measure and maintain the effectiveness of the Plans.

The Company's subsidiary, Apache, is a member of Oil Spill Response Limited (OSRL), a large international oil spill response cooperative, which entitles any affiliated entity worldwide to access OSRL's services. OSRL maintains aircraft available for global dispersant application and has active recovery boom systems that can be used for offshore, nearshore, or shoreline responses. In addition to the services and equipment provided to all members of OSRL, the Company maintains membership to supplementary services from OSRL, including the U.K. Continental Shelf (UKCS) Aerial Surveillance, OSPRAG Capping Stack, and Dispersant Stockpile, providing equipment and services specifically tailored for an emergency response in the North Sea.

In the event of a spill in the Gulf of America, Clean Gulf Associates (CGA) is the primary oil spill response organization available to the Company. Apache is a member of CGA, a not-for-profit association of producing and pipeline companies operating in the Gulf of America. CGA was created to provide a means of effectively staging response equipment and providing immediate spill response for its member companies' operations in the Gulf of America. CGA equipment includes skimming vessels, barges, boom, and dispersants.

Additionally, the Company has contracted with Wild Well Control Company for contingency planning for and response to uncontrolled subsea well events and other drilling activities. This includes the use of subsea dispersant systems and field deployment of one of Wild Well Control's containment system capping stacks.

Competitive Conditions

The oil and gas industry is highly competitive in the exploration for and acquisitions of reserves, the acquisition of oil and gas leases, equipment, and personnel required to find and produce reserves, and the gathering and marketing of oil, gas, and NGLs. The Company's competitors include national oil companies, major integrated oil and gas companies, other independent oil and gas companies, and participants in other industries supplying energy and fuel to industrial, commercial, and individual consumers.

Certain of the Company's competitors may possess financial or other resources substantially larger than the Company possesses or have established strategic long-term positions and maintain strong governmental relationships in countries in which the Company may seek new entry. As a consequence, the Company may be at a competitive disadvantage in bidding for leases or drilling rights.

However, the Company believes its diversified portfolio of core assets, which comprises large acreage positions and well-established production bases across multiple geographic areas, its balanced production mix between oil and gas, its management and incentive systems, and its experienced personnel give it a strong competitive position relative to many of the Company's competitors who do not possess similar geographic and production diversity. The Company's global position provides a large inventory of geologic and geographic opportunities in the geographic areas in which it has producing operations to which it can reallocate capital investments in response to changes in commodity prices, local business environments, and markets. This also reduces the risk that the Company will be materially impacted by an event in a specific area or country.

Governmental Regulation

The Company's U.S. operations are subject to federal, state, and local laws and regulations, including restrictions on production, changes in taxes and other amounts payable to governments, price or gathering rate controls, environmental protection laws and regulations, standards for drilling, completing, and equipping oil and gas wells, standards for plugging, abandonment, decommissioning, and site restoration activities, and security for plugging, abandonment, and decommissioning obligations, including in the Gulf of America. For discussions of the risks the Company faces related to regulation, see the information set forth under "Risks Related to Governmental Regulation and Political Matters," "Risks Related to Climate Change, Energy Transition, and ESG Matters," and "Risks Related to International Operations" in Item 1A—Risk Factors.

Regulatory requirements affecting the Company's operations are frequently proposed, revised, delayed, challenged in litigation, enjoined or stayed by courts, withdrawn by agencies, or modified through subsequent administrative and legislative actions, including in the U.S. through the use of the Congressional Review Act. As a result, the scope, timing, and practical impact of regulatory change can be difficult to predict and may change rapidly, including across election cycles and as agencies adjust enforcement priorities.

Hydraulic Fracturing Regulation

The Company routinely uses fracturing techniques in the U.S. and other regions to expand the available space for oil and natural gas to migrate toward the wellbore, typically at substantial depths in formations with low permeability. Governmental entities have previously taken actions to regulate hydraulic fracturing. These activities and the associated water disposal activities are under scrutiny due to their potential environmental and physical impacts, including possible water contamination and possible links to induced seismicity.

Climate Change

Due to climate change concerns, numerous proposals to monitor and limit emissions of greenhouse gas (GHG) have been made and are likely to continue to be made at the federal, state, and local levels of government and by the governments of other nations. There has been discussion in countries where the Company operates, including the U.S., regarding changes in legislation or heightened regulation of GHGs, including to monitor and limit existing emissions of GHGs and to restrict or eliminate future emissions, or to assess a charge on methane emissions in the oil and gas industry.

In the U.S., regulatory activity related to methane and GHG emissions has included, and is expected to continue to include, changes to monitoring, reporting, leak detection and repair, flaring, and emissions control requirements applicable to oil and gas operations. For example, the U.S. Environmental Protection Agency (EPA) has adopted and/or proposed revisions to methane and volatile organic compound standards for new and existing sources in the oil and gas sector, and the EPA's Greenhouse Gas Reporting Program has been subject to ongoing rulemaking activity, including recent activity to reduce the

reporting for petroleum and natural gas systems. In addition, the Inflation Reduction Act of 2022 established a Methane Emissions Reduction Program that contemplates the assessment of a "waste emissions charge" for certain methane emissions from facilities already subject to reporting requirements, which has been delayed until 2034. Additionally, on February 12, 2026, the EPA finalized a rescission of the 2009 Endangerment Finding for GHGs under Section 202(a) of the Clean Air Act; this action, and any resulting legal challenges or subsequent governmental actions, could affect the broader regulatory landscape and related compliance expectations. Further, these developments, and related state implementation actions, could increase compliance costs, require additional capital expenditures, and result in operational constraints, including with respect to measurement and monitoring, equipment retrofits, and flaring practices.

Additionally, various states and groups of states have adopted, and others continue to consider adopting, legislation, regulations, or other regulatory initiatives that are focused on such areas as GHG cap-and-trade programs, carbon taxes, reporting and tracking programs, restriction of emissions, electric vehicle mandates, and combustion engine phaseouts. Any such legislation, regulations, or other regulatory initiatives, if enacted, or additional or increased taxes, assessments, or GHG-related fees on the Company's operations could lead to increased operating expenses or cause the Company to make significant capital investments for infrastructure modifications, including as a result of recent federal actions to reconsider and rescind certain GHG-related regulatory determinations and standards, which may create regulatory uncertainty and result in increased state-level and litigation activity. Certain jurisdictions have also adopted or proposed climate-related disclosure or supply-chain reporting regimes, which could increase compliance and reporting costs and, depending on applicability, require additional processes, controls, and assurance.

Endangered or Protected Species

The Company's operations in its operating areas could be adversely impacted by seasonal, periodic, or permanent restrictions or limitations relating to oil and gas operations to protect certain wildlife with habitats or migratory paths within such operational areas. Such restrictions or limitations can include, without limitation, prohibited drilling and development activity in certain areas or restricted activities during specific seasons or the employment of costly mitigation measures. New designations of previously unprotected species as threatened, endangered, or protected species could cause the Company to incur significant additional costs to implement required protective measures or could limit the Company's ability to effectively and efficiently develop and produce reserves.

Treatment and Disposal of Produced Water Regulation

The treatment and disposal of produced water is highly regulated and restricted. Regulators in some states, such as the Railroad Commission of Texas, have taken actions to limit disposal well activities (including orders to temporarily shut down or to curtail water injection) and to require the monitoring of seismic activity. While the Company remains focused on reusing or recycling water over disposal of water, the Company's costs for obtaining and disposing of water could increase significantly if reusing and recycling water becomes impractical.

Environmental Compliance

As an owner or lessee and operator of oil and gas properties and facilities, the Company is subject to numerous federal, state, local, and foreign laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations, subject the lessee to liability for pollution damages and require suspension or cessation of operations in affected areas. Although environmental requirements have a substantial impact upon the energy industry as a whole, the Company does not expect that these requirements will affect it differently, to any material degree, than other companies in the oil and gas industry; however, the Company's compliance costs and operational constraints may increase as requirements evolve.

The Company has made and will continue to make expenditures in its efforts to comply with these requirements, which the Company believes are necessary business costs in the oil and gas industry. The Company has established policies for continuing compliance with environmental laws and regulations, including regulations applicable to its operations in all countries in which it does business. The Company has established operating procedures and training programs designed to limit the environmental impact of its field facilities and identify and comply with changes in existing laws and regulations. The costs incurred under these policies and procedures are inextricably connected to normal operating expenses such that the Company is unable to separate expenses related to environmental matters; however, the Company does not currently expect that compliance with existing environmental laws and regulations will have a material adverse impact on its capital expenditures, earnings, or competitive position, though future regulatory changes could increase the Company's costs and capital requirements.

ITEM 1A. ***RISK FACTORS***

The Company's business activities and the value of its securities are subject to significant hazards and risks, including those described below. If any of such events should occur, the Company's business, financial condition, liquidity, and/or results of operations could be materially harmed, and holders and purchasers of APA's securities could lose part or all of their investments. Additional risks and uncertainties not presently known to the Company or that the Company currently considers immaterial may also adversely affect the Company.

RISKS RELATED TO COMMODITY PRICES, DEMAND, AND PRODUCTION

Crude oil, natural gas, and NGL prices and their volatility could adversely affect the Company's operating results and the price of APA's common stock.

The Company's revenues, operating results, future rate of growth, and carrying value of its oil and gas properties depend highly upon the prices it receives for its sales of crude oil, natural gas, and NGL products. Historically, the markets for these commodities have been volatile and are likely to continue to be volatile in the future. For example, the NYMEX daily settlement price for the prompt month oil contract in 2025 ranged from a high of $80.73 per barrel to a low of $55.44 per barrel, and the NYMEX daily settlement price for the prompt month natural gas contract in 2025 ranged from a high of $9.86 per MMBtu to a low of $2.65 per MMBtu.

The market prices for crude oil, natural gas, and NGLs depend on factors beyond the Company's control, including:

- demand, which fluctuates with changes in market and economic conditions;
- worldwide and domestic supplies and/or inventories of crude oil, natural gas, and NGLs and the availability of related pipeline, transportation, import/export, and refining capacity and infrastructure;
- actions taken by foreign oil and gas producing nations, including the Organization of the Petroleum Exporting Countries (OPEC) and non-OPEC members that participate in OPEC initiatives (OPEC+);
- political conditions and events in oil and gas producing regions, including instabilities, changes in governments, or armed conflicts;
- the price, competitiveness, decision to use, and availability of alternative fuels and energy sources, including coal, biofuels, and renewables;
- increased competitiveness of, and demand for, alternative energy sources;
- technological advances affecting energy supply and energy consumption, including those that alter fuel choices;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- the impact of political pressure and the influence of environmental groups, investors, and other stakeholders on decisions and policies related to the oil and gas industry, including with respect to environmental, social, and governance matters;
- the timing, scope, implementation, and potential judicial review of energy transition and climate-related policies and regulations (such as methane fees, emissions reporting requirements, carbon pricing mechanisms, and other climate-related measures);
- domestic and foreign governmental regulations and taxes, including changes or initiatives to address the impacts of global climate change, hydraulic fracturing, methane emissions, flaring, or water disposal; and
- the overall economic environment, including rates of growth, trade tensions, and increasing inflationary pressure.

Low prices have previously adversely affected and could from time to time in the future adversely affect the Company's revenues, operating income, cash flow, and proved reserves, and a prolonged period of low prices could have a material adverse impact on the Company's results of operations and cash flows and limit its ability to fund capital expenditures and return capital to its shareholders. Without the ability to fund capital expenditures, the Company would be unable to replace reserves and production. Sustained low prices of crude oil, natural gas, and NGLs could also further adversely impact the Company's business, including by weakening the Company's financial condition and reducing its liquidity, limiting the Company's ability to fund planned capital expenditures and operations, causing the Company to delay or postpone some of its capital projects or reallocate capital to different projects or regions, limiting the Company's access to sources of capital, such as equity and long-term debt, or reducing the carrying value of the Company's oil and gas properties, resulting in additional non-cash impairments.

The Company's ability to sell crude oil, natural gas, or NGLs, receive market prices for these commodities, meet volume commitments under transportation services agreements, and/or economically market third-party volumes may be adversely affected by pipeline and gathering system capacity changes, the inability to procure and resell volumes economically, various transportation interruptions or expansions, and the financial distress or insolvency of midstream or transportation providers that could reduce available capacity or disrupt service.

A portion of the Company's crude oil, natural gas, and NGL production in any region may be, and previously have been, interrupted, limited, or shut in from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, cyberattacks or terrorist events, or capital constraints, financial distress, or insolvency of third-party providers that limit the ability of such third parties to construct gathering systems, processing facilities, or interstate pipelines to transport the Company's production. Additionally, the Company has previously and may in the future voluntarily curtail production in response to market conditions, such as weak or negative prices. If a substantial amount of the Company's production is interrupted or curtailed at the same time, it could temporarily adversely affect the Company's cash flows. Further, if the Company is unable to procure and resell third-party volumes at or above a net price that covers the cost of transportation, the Company's cash flows could be adversely affected. As additional gas pipeline takeaway capacity in the Permian Basin comes online, the spread between Permian and Gulf Coast gas prices may compress, which would reduce the Company's gain on third-party oil and gas purchases and sales.

The Company's commodity price and other risk management and trading activities, including interest rate and foreign exchange hedging, and contracts priced in foreign currencies may prevent it from benefiting fully from price increases and market movements and may expose it to other risks.

To the extent that the Company engages in price risk management activities to protect itself from commodity price declines, the Company may be prevented from realizing the benefits of price increases. Similarly, to the extent the Company enters into derivative contracts to manage exposure to interest rate or foreign exchange risk or enters into contracts priced in a foreign currency, it may be limited in its ability to benefit from favorable movements in interest rates or currency exchange rates or may incur additional expense converting to a foreign currency to fund contractual obligations. The Company's hedging arrangements may expose it to the risk of financial loss, including when production falls short of the hedged volumes, price-basis differentials widen, a hedging counterparty defaults, or an unexpected event materially impacts commodity prices. In addition, because the Company does not apply hedge accounting to its derivative instruments, changes in the fair value of derivatives are recognized in current-period earnings, which may introduce earnings volatility even when the underlying exposure is intended to be economically hedged.

Public health events, workforce disruptions, or similar global or regional events have previously and may in the future adversely impact the Company's business, financial condition, and results of operations.

Public health events, including related workforce availability constraints, travel restrictions, supply chain disruptions, or government-mandated operational limitations, have previously adversely impacted and may from time to time in the future adversely impact the global economy, cause significant volatility in financial markets, and reduce the demand for, and the prices of, oil, natural gas, and NGLs, which may materially adversely affect the Company's business, financial condition, cash flows, and results of operations.

RISKS RELATED TO OPERATIONS, SAFETY, AND EXPLORATION AND DEVELOPMENT PROJECTS

The Company's operations involve a high degree of operational risk, particularly risk of personal injury, damage to or loss of property, and environmental accidents.

The Company's operations are subject to hazards and risks inherent in the drilling, production, and transportation of crude oil, natural gas, and NGLs, including well blowouts, explosions, fires, cratering, pipeline or other facility ruptures and

spills, adverse weather conditions, including those impacting the Company's offshore operating areas, surface spillage and ground water contamination, and failure or loss of equipment. These events, including ineffective containment of such events, have previously and could in the future result in property damages, personal injury, environmental pollution, and other damages for which the Company could be liable. If a significant amount of the Company's production is interrupted, containment efforts prove to be ineffective, or litigation arises as the result of a catastrophic occurrence, the Company's cash flows and, in turn, its results of operations could be materially and adversely affected.

The Company has previously not realized, and may in the future not realize, an adequate return on wells that it drills.

Drilling for oil and gas involves numerous risks, including that the Company may not encounter commercially productive oil or gas reservoirs or may not recover all or any portion of its investment in the wells it drills. Management has previously determined, and may in the future determine, that wells or development projects have failed to meet expected economic thresholds because of drilling results, cost inflation, commodity price volatility, revised development plans, demand for oil, natural gas, and NGLs, or other information, and in such cases, the Company may elect not to pursue or complete those activities. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations are subject to a variety of risks, including unexpected drilling conditions (such as pressure or formation irregularities), equipment failures or accidents, catastrophic events, marine risks, adverse weather conditions, and increases in the cost of or shortages or delays in the availability of drilling rigs, equipment, and labor. In addition, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Any such events could have an adverse effect on the Company's future results of operations and financial condition. Exploration costs and dry hole expenses incurred by the Company during the reporting period are further discussed in this Annual Report on Form 10-K and reflected in the consolidated financial statements included herein.

Frontier exploration and development projects, including those in new or re-entered jurisdictions, involve heightened operational, regulatory, and execution risks that could adversely affect the Company's results of operations and financial condition.

The Company's exploration and development portfolio includes higher-risk frontier opportunities, including in Alaska and offshore Suriname and Uruguay, which may involve extended timelines, complex permitting and stakeholder processes, logistical constraints, and heightened regulatory scrutiny. Operations in new countries or areas where the Company has limited recent operating history may also require the establishment or reestablishment of local relationships, workforce and supply chains, regulatory familiarity, and infrastructure, and may expose the Company to unfamiliar legal frameworks, fiscal regimes, community engagement expectations, and political dynamics.

Delays or adverse outcomes in permitting, litigation (including parties seeking legal or equitable relief to prevent or otherwise limit exploration activities, such as for the acquisition of seismic data or for drilling operations), appraisal drilling, or commercial development decisions could result in the deferral, impairment, or partial or complete loss of anticipated value of exploration, development, and production assets and the recognition of additional exploration expense. In addition, unanticipated technical, geological, operational, or regulatory challenges in such jurisdictions could increase capital requirements, extend project timelines, or adversely affect the commercial viability of these projects. These risks may be amplified in jurisdictions where regulatory regimes are evolving or where litigation or public opposition to offshore exploration activities has increased.

The Company's insurance policies do not cover all of the risks the Company faces, which could result in significant financial exposure.

Exploration for and production of crude oil, natural gas, and NGLs involves hazards, which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property or the environment. The Company's international operations are also subject to political and economic risks. The insurance coverage that the Company maintains against certain losses or liabilities arising from its operations may be inadequate to cover any such resulting liability; moreover, insurance is not available to the Company against all operational risks. While certain insurance policies of the Company may provide coverage for such events, if the Company were to incur a significant liability for which it was not fully insured, then it could have a material adverse effect on the Company's financial position, results of operations, and cash flows. In addition, if such an event were to occur, then the proceeds of any such insurance may not be paid in a timely manner or may not be sufficient to cover all of the Company's losses.

A cyberattack targeting systems and infrastructure used by the Company or others in the oil and gas industry may adversely impact the Company's operations.

There are numerous and evolving risks to the Company's data, technology, and information systems from cyber threat actors, including criminal hackers, state-sponsored intrusions, industrial espionage, and employee malfeasance. The Company's operations are dependent on digital technologies, including to estimate reserves, process financial and operating data, analyze drilling information, and communicate with personnel. Unauthorized access to the Company's data, technology, and information systems could lead to operational disruption, communication interruption, disruption in access to financial reporting systems, and loss, misuse, or corruption of data and proprietary information. In addition, unauthorized access to third party information systems could interrupt the oil and gas distribution and refining systems in the U.S. and abroad, which are necessary to transport and market the Company's production. Cyberattacks directed at oil and gas distribution systems have previously and could again in the future damage critical distribution and storage assets or the environment. The potential impacts of a cyber incident could be made worse by a delay or failure to detect the occurrence, continuance, or extent of such an incident.

The Company may be required to expend further resources to protect its digital systems and data as cyber threat actors become more sophisticated and as regulations related to cyberattacks become more complex. Cyberattacks, including malicious software, data privacy breaches by employees, insiders, or others with authorized access to the Company's systems, cyber or phishing attacks, ransomware attacks, supply chain vulnerabilities, business email compromises, other attempts to gain unauthorized access to the Company's data and systems, and other electronic security breaches could have a material adverse effect on the Company's business, cause it to incur a material financial loss, subject it to possible legal claims and liability, and/or damage its reputation.

While the Company has not suffered any material losses as a result of cyberattacks, there is no assurance that the Company will not suffer such losses in the future. See Item 1C—Cybersecurity for additional information regarding the Company's cybersecurity risk management and governance.

Material differences between the estimated and actual timing of critical events or costs may affect the completion and commencement of production from development projects.

The Company is involved in several large development projects, and the completion of these projects may be delayed beyond the Company's anticipated completion dates. These projects may be delayed by approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, cost inflation, availability, manufacturing, and delivery schedules of critical vessels and equipment, customs and logistics, cash-call timing or funding shortfalls, and other unforeseen events. Delays and differences between estimated and actual timing of critical events and development costs (including for equipment and personnel) may adversely affect the Company's large development projects (including forcing the Company to abandon such projects) and its ability to participate in large-scale development projects in the future.

RISKS RELATED TO RESERVES, ESTIMATES, AND LEASEHOLDS

Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.

The production rate from oil and natural gas properties generally declines as reserves are depleted, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, future oil and gas production is highly dependent upon the Company's level of success in adding reserves through exploration and development activities, identifying additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves through engineering studies, or acquiring additional properties containing proved reserves. As oil or natural gas prices increase, the Company's cost for additional reserves could also increase.

The Company may fail to fully identify potential problems related to acquired reserves or to properly estimate those reserves.

Although the Company performs a review of properties that it acquires, which the Company believes is consistent with industry practices, such reviews are inherently incomplete, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and future production rates and costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates. There can be no assurance that acquisitions will not adversely impact the Company's operating results, particularly during their integration into the Company's ongoing operations.

Crude oil, natural gas, and NGL reserves are estimates, and actual recoveries may vary significantly.

There are numerous uncertainties inherent in the process of estimating crude oil, natural gas, and NGL reserves and their value, which is highly subjective and relies on the quality of available data and the accuracy of engineering and geological interpretation. The Company's reserves estimates are based on 12-month average prices, except where contractual arrangements exist, consistent with applicable SEC pricing and reporting rules. Therefore, changes in future commodity prices or in development plans can materially impact reported reserves. The estimates of the Company's proved reserves and estimated future net revenues also depend on a number of factors and assumptions that may vary considerably from actual results, including historical production from the area compared with production from other areas, the results of drilling, testing, and production for a reservoir over time, the use of volumetric analysis versus production history, the effects of changes in laws (including emissions regulations, infrastructure modernization requirements, and taxes), future operating, workover, and remediation costs, and capital expenditures. For example, during 2024, the Company recorded $796 million of impairments for certain of its North Sea proved properties as a result of several new regulatory guidelines and obligations in the U.K. Accordingly, reserves estimates may be subject to adjustment, and actual production, revenue, and expenditures with respect to the Company's reserves likely will vary, possibly materially, from estimates. In addition, realization or recognition of proved undeveloped reserves will depend on the Company's development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Certain of the Company's undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A sizable portion of the Company's acreage is currently undeveloped. Unless production in paying quantities is established on units containing certain of these leases during their terms, the leases will expire. If the leases expire, the Company will lose its right to develop the related properties. The Company's drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

RISKS RELATED TO COUNTERPARTIES AND JOINT VENTURES

The credit risk of financial institutions could adversely affect the Company and result in a significant loss.

The Company is party to numerous transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, other investment funds, and other institutions, including in the form of derivative transactions in connection with any hedges and claims under the Company's insurance policies, which expose the Company to credit risk in the event of default of the counterparty. Deterioration or volatility in the credit or financial markets, changes in commodity prices, and changes in a counterparty's liquidity may affect the counterparties' ability to fulfill their existing obligations to the Company. In addition, if any lender under the Company's credit facilities is unable to fund its commitment, the Company's liquidity may be reduced by an amount up to the aggregate amount of such lender's commitment thereunder. Furthermore, the bankruptcy of one or more of the Company's counterparties or some other similar proceeding or liquidity constraint might make it unlikely that the Company would be able to collect all or a significant portion of amounts owed to it by the distressed entity or entities, and the Company could incur a significant loss.

The distressed financial conditions of the Company's partners and the purchasers of the Company's products or assets have had and could have an adverse impact on the Company in the event they are unable to reimburse the Company for their share of costs or to pay the Company for the products or services the Company provides.

The Company is exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. As a result of previous severe declines in commodity prices, some of the Company's customers and non-operating partners experienced severe financial problems. The Company cannot provide assurance that one or more of its financially distressed customers or non-operating partners will not default on their obligations to the Company (including as a result of their filing for bankruptcy or other liquidity constraints) or that such a default or defaults will not have a material adverse effect on the Company's business, financial position, future results of operations, or future cash flows.

The Company's liabilities, including for the decommissioning of previously owned assets, could be adversely affected in the event one or more of its transaction counterparties are financially distressed or become the subject of a bankruptcy case.

The agreements relating to the Company's divestment of domestic and international assets generally contain provisions pursuant to which liabilities related to past and future operations (one of the most significant of which is the decommissioning

of wells and facilities) are allocated between the parties by means of liability assumptions, indemnities, escrows, trusts, surety bonds, letters of credit, and similar arrangements. One or more of the counterparties in these transactions could fail to perform its obligations under these agreements as a result of financial distress or bankruptcy, which may force the Company to use available cash to cover the costs of such obligations, pending final resolution of any claims the Company may have against the counterparty, which could adversely impact the Company's cash flows, operations, or financial condition.

For additional information regarding Apache's prior Gulf of America properties and the bankruptcy of the purchaser of those properties, see the information set forth under "Potential Decommissioning Obligations on Sold Properties" in Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company does not always control decisions made under joint operating agreements or joint ventures, and the parties to such agreements or ventures may fail to meet their obligations.

The Company conducts many of its exploration and production (E&P) operations through joint operating agreements or joint ventures with other parties, including state-owned or government-controlled entities. The Company may not control decisions made under such agreements or ventures, either because it does not have a controlling interest in the venture or is not an operator under the agreement. The other parties to these arrangements may have economic, business, or legal interests or goals that are inconsistent with the Company's, including priorities set by governmental or state-owned counterparties, or that are influenced by governmental policy, fiscal priorities, or broader economic or social conditions, which may affect decision making, capital allocation, payment timing, or operational approvals. Therefore, decisions may be made that the Company does not believe are in its best interest. Moreover, parties to such agreements or ventures may be unable to meet their economic or other obligations, and the Company may be required to fulfill those obligations alone. In either case, the value of the investment and the Company's business and financial condition may be adversely affected.

RISKS RELATED TO CAPITAL MARKETS, LIQUIDITY, AND TAX MATTERS

A downgrade in the Company's credit rating could negatively impact its cost of and ability to access capital.

The Company receives debt ratings from the major credit rating agencies in the U.S. Factors that may impact the Company's credit ratings include its debt levels, planned asset purchases or sales, and near-term and long-term production growth opportunities. Liquidity, asset quality, cost structure, product mix, commodity pricing levels, and other factors are also considered by the rating agencies. A ratings downgrade could adversely impact the Company's ability to access debt markets in the future and increase the cost of future debt. Past ratings downgrades have required, and any future downgrades may require, the Company to post letters of credit or other forms of collateral for certain obligations.

Market conditions may restrict the Company's ability to obtain funds for future development and working capital needs, which may limit its financial flexibility.

The financial markets are subject to fluctuation and are vulnerable to unpredictable swings. The Company has a significant development project inventory and an extensive exploration portfolio, which will require substantial future investment. The Company and/or its partners may need to seek financing to fund these or other future activities. The Company's future access to capital, as well as that of its partners and contractors, could be limited if the debt or equity markets are constrained or if financial institutions, investors, or insurers limit exposure to oil and gas companies or modify underwriting standards in response to climate-related or other policy developments. This could significantly delay development of the Company's property interests.

The Company's syndicated revolving credit facilities currently mature in January 2030. There is no assurance of the terms upon which potential lenders under future agreements will make loans or other extensions of credit available to the Company or its subsidiaries or the composition of such lenders.

The Company's ability to declare and pay dividends, and to repurchase common stock, is subject to limitations.

The payment of future dividends on, and any repurchases of, the Company's common stock are each subject to the discretion of the Board of Directors, taking into consideration, among other factors, the Company's operating results, available cash, overall financial condition, credit risks, capital requirements, restrictions under the Company's indentures and other financing agreements, restrictions under Delaware law, general business and market conditions, and other factors the Board of Directors deems relevant. The Board of Directors is not required to declare dividends on or repurchase APA's common stock and may decide not to declare dividends or repurchase common stock at the current rate or at all. Any downward revision in the

amount of dividends the Company pays to shareholders, or reduction in the pace of share repurchases, could have an adverse effect on the market price of the Company's common stock.

Actions by advocacy groups to advance climate change and energy transition initiatives, unfavorable ESG ratings, and funding limitation initiatives may lead to negative investor and public sentiment toward the Company and to the diversion of capital from companies in the oil and gas industry, which could negatively impact the Company's access to and costs of capital or the market for the Company's securities.

Organizations that provide information to investors on corporate governance and related matters have developed ratings for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform and advise their investment and voting decisions. Unfavorable ESG ratings may lead to negative investor and public sentiment toward the Company, which may cause the market for the Company's securities to be negatively impacted.

In addition, a number of advocacy groups have campaigned for governmental and private action to influence change in the business strategies of oil and gas companies, including through the investment and voting practices of investment advisers, public pension funds, universities, and other members of the investing community. These campaign efforts have resulted in the divestment of investments in the oil and gas industry and increased pressure on lenders and other financial services companies to limit or curtail activities with oil and gas companies. If investors or financial institutions shift funding away from companies in the oil and gas industry, the Company's access to and costs of capital or the market for the Company's securities may be negatively impacted.

The Company faces strong industry competition that may have a significant negative impact on the Company's results of operations.

Strong competition exists in all sectors of the oil and gas E&P industry. The Company competes for leases, equipment, labor, key personnel, and marketing of crude oil, natural gas, and NGL production, the prices of which impact the costs of properties and the financial resources available to pursue acquisitions. These competitive pressures may have a significant negative impact on the Company's results of operations.

The Company's ability to utilize net operating losses and other tax attributes to reduce future taxable income may be limited if the Company experiences an ownership change.

As described in Note 9—Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, the Company has substantial net operating loss carryforwards (NOLs) and other tax attributes available to potentially offset future taxable income. If the Company were to experience an "ownership change" under Section 382 of the Internal Revenue Code of 1986, as amended, which is generally defined as a greater than 50 percentage point change, by value, in the Company's equity ownership by five-percent shareholders over a three-year period, the Company's ability to utilize its pre-change NOLs and other pre-change tax attributes to potentially offset its post-change income or taxes may be limited. Such a limitation could materially adversely affect the Company's operating results or cash flows.

The Company's ability to realize its deferred tax assets may be limited if it experiences changes in expected future cash flows related to reserves or ARO.

As described in Note 9—Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, the Company assesses the realizability of its deferred tax assets based on its ability to generate sufficient future taxable income. Future changes in expected cash outflows for ARO or inflows from reserves could impact the Company's ability to realize its deferred tax assets in future periods.

APA is a holding company and is dependent on the operations of and distributions from its subsidiaries, including Apache.

As a holding company, APA has no business operations of its own, and its primary assets are its ownership interests in its subsidiaries, including Apache. As a result, APA relies on cash flows from its subsidiaries to pay dividends on, and make repurchases of, its common stock and to meet its financial obligations, including to service any amounts outstanding under its notes, debentures, credit agreements or commercial paper program, and any additional financial obligations that the Company may incur from time to time in the future. If the subsidiaries are limited in their ability to distribute cash to the Company, such as through legal or contractual limitations, or if the subsidiaries' earnings or other available assets are not sufficient to pay distributions or make loans to the Company in the amounts or at the times necessary to meet the Company's financial obligations, then the Company's financial condition, cash flows, and reputation may be materially adversely affected.

RISKS RELATED TO GOVERNMENTAL REGULATION AND POLITICAL MATTERS

The Company may incur significant costs related to environmental matters.

As an owner or lessee and operator of oil and gas properties, the Company is subject to various federal, state, local, and foreign laws and regulations relating to the discharge of materials into and protection of the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution cleanup and other remediation activities resulting from operations, subject the lessee to liability for pollution and other damages, limit or constrain operations in affected areas, require significant capital expenditures to comply with increasingly strict environmental laws and regulations, and require suspension or cessation of operations in affected areas. The Company's efforts to limit its exposure to such liability and cost may prove inadequate and result in significant adverse effects to the Company's results of operations and cash flows.

The Company's U.S. operations are subject to governmental risks.

The Company's U.S. operations have been, and at times in the future may be, affected by political developments and by federal, state, and local laws and regulations, including restrictions on production, changes in taxes and other amounts payable to governments, price or gathering rate controls, environmental protection laws and regulations, and security for plugging, abandonment, and decommissioning obligations, including in the Gulf of America.

New political developments, the enactment of new or stricter laws or regulations or other governmental actions impacting the Company's U.S. operations, and increased liability for companies operating in the oil and gas E&P industry may adversely impact the Company's results of operations.

Proposed federal, state, or local regulation regarding hydraulic fracturing could increase the Company's operating and capital costs.

The Company routinely uses fracturing techniques in the U.S. and other regions to expand the available space for oil and natural gas to migrate toward the wellbore, typically at substantial depths in formations with low permeability. Governmental entities have previously taken actions to regulate hydraulic fracturing, and future regulatory approaches may vary significantly across jurisdictions and over time. Such regulations may impose more stringent permitting, reporting, and well construction requirements or otherwise seek to ban fracturing activities. These activities and the associated water disposal activities are under scrutiny due to their potential environmental and physical impacts, including possible water contamination and possible links to induced seismicity. Any new federal, state, or local restrictions on hydraulic fracturing could result in increased compliance costs or additional restrictions on the Company's U.S. operations.

Changes in tax rules and regulations, or interpretations thereof, may adversely affect the Company's business, financial condition, and results of operations.

Federal, state, and foreign income tax laws affecting oil and gas exploration, development, and extraction may be modified by administrative, legislative, or judicial interpretation at any time. For example, the U.K. enacted the Energy Profits Levy (EPL), which (prior to recent law changes) assessed an additional levy of 35 percent, effective for the period of January 1, 2023, through March 31, 2028, on the profits of oil and gas companies operating in the U.K. and the U.K. Continental Shelf. Further changes to the EPL regime were enacted in 2025. Such changes, effective for the period of November 1, 2024, through March 31, 2030, increased the levy to 38 percent, removed certain allowances, and extended the EPL period. During 2024, the Company performed an economic assessment of its North Sea assets in light of the significant tax levies, along with several new regulatory guidelines and obligations surrounding modernization of aging infrastructure, and determined that expected returns did not economically support making investments required under the combined impact of the regulations and now expects to cease production at its facilities in the North Sea prior to 2030.

Additionally, in the U.S., the Inflation Reduction Act of 2022 introduced a new 15 percent corporate alternative minimum tax (Corporate AMT) for taxable years beginning after December 31, 2022, on applicable corporations with an average annual adjusted financial statement income (AFSI) that exceeds $1.0 billion for any three consecutive tax years preceding the tax year at issue. Effective January 1, 2024, the Company is subject to the Corporate AMT. Accordingly, any resulting Corporate AMT liability could adversely affect the Company's future financial results, including earnings and cash flows.

Previous legislative proposals, if enacted into law, could make significant changes to tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas E&P companies. These changes include, but are not limited to, the repeal of the percentage depletion allowance for oil and gas properties, the elimination of current deductions for intangible drilling and development costs, and an extension of the amortization period for certain geological and geophysical expenditures. The passage or adoption of these changes, or similar changes, could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development. The Company is unable to predict whether any of these changes or other proposals will be enacted. Any such changes could adversely affect the Company's business, financial condition, and results of operations.

Changes to laws, regulations, guidance, and industry standards, or interpretations thereof, or higher than anticipated costs for asset retirement and decommissioning obligations could adversely affect the Company's results of operations and cash flows.

The Company is subject to extensive requirements governing the plugging, abandonment, and decommissioning of wells, facilities, sites, and related infrastructure. The cost, timing, and other aspects of these activities are uncertain and may be materially affected by changes in laws, regulations, guidance, or industry standards and by changes in the Company's understanding and implementation of the decommissioning tasks and activities required, including the complexity thereof. There is an increased focus on decommissioning requirements, financial assurance, and environmental remediation in countries where the Company operates. New or revised rules, guidance, interpretations, or contractual frameworks, or the administration thereof, could expand the scope of required activities, alter timelines, or increase financial guarantees or other forms of financial security obligations, resulting in higher costs and greater cash flow demands.

For the Company's decommissioning obligations in the North Sea, the regulatory framework and the standards applicable to removal and seabed clearance may continue to evolve. For example, on September 5, 2025, the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED) opened a consultation on draft supplementary guidance on the methodology for considering derogations for removal of certain subsea structures under OSPAR Decision 98/3. The consultation materials emphasize a policy objective of achieving a "clear seabed," a presumption in favor of removal, and an expectation of a reduction in derogations, with a revised methodology that evaluates full removal against certain criteria before a derogation proposal may proceed. While the consultation period ended on November 14, 2025, and the proposal has not been finalized, if ultimately adopted and implemented, such changes, together with any related changes in regulatory expectations or enforcement, could require more extensive removal, seabed clearance, monitoring, or documentation than the Company currently anticipates, materially increase the Company's estimated decommissioning obligations and costs in the North Sea, and adversely affect the Company's cash flows and results of operations.

Additionally, inflation, supply constraints, and limited contractor and vessel availability have raised decommissioning costs in recent periods. If decommissioning spending materially exceeds current estimates or the Company's joint venture partners, current owners of the Company's previous assets, or other third parties (including governments) responsible for funding or reimbursing decommissioning costs fail to meet their obligations, the Company's cash flows, capital resources, and liquidity could be adversely affected.

RISKS RELATED TO CLIMATE CHANGE, ENERGY TRANSITION, AND ESG MATTERS

The impacts of climate change, energy transition policies, and ESG-related initiatives could adversely affect the Company's business, operating results, and financial condition.

Attention continues to be given to corporate activities related to climate change and energy transition. This focus, together with shifting 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, have resulted in increased availability of, and demand for, energy sources other than oil and natural gas, including wind, solar, and hydroelectric power, and the development of, and increased demand from consumers and industries for, lower-emission products and services, including electric vehicles and renewable residential and commercial power supplies, as well as more energy-efficient products and services.

Further developments could adversely impact the demand for products powered by or manufactured with hydrocarbons and the demand for, and in turn the prices the Company receives for, its crude oil, natural gas, and NGL products, which could materially and adversely affect the Company's business and financial performance.

Weather and climate may have a significant adverse impact on the Company's revenues and production.

Demand for oil and natural gas is, to a significant degree, dependent on weather and climate, which impact the price the Company receives for the commodities it produces. In addition, the Company's exploration, development, and production activities and equipment have been and can be adversely affected by severe weather, such as freezing temperatures, hurricanes in the Gulf of America, or major storms in the North Sea, each of which have previously caused and may cause a loss of production from temporary cessation of activity or lost or damaged equipment. The Company's planning for normal climatic variation, insurance programs, and emergency recovery plans may inadequately mitigate the effects of such weather conditions, and not all such effects can be predicted, eliminated, or insured against.

Changes to existing regulations related to emissions and the impact of any changes in climate could adversely impact the Company's business.

Certain countries where the Company operates, including the U.K., either tax or assess some form of greenhouse gas (GHG) related fees on the Company's operations. Exposure has not been material to date, although a change in existing regulations could adversely affect the Company's cash flows and results of operations. Additionally, there has been discussion in other countries where the Company operates, including previous discussion in the U.S. when the regulatory landscape at the federal level was more focused on these issues, regarding changes in legislation or heightened regulation of GHGs, including to monitor and limit existing emissions of GHGs, to restrict or eliminate future emissions, or to assess a charge on methane emissions in the oil and gas industry. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations, or other regulatory initiatives that are focused on such areas as GHG cap-and-trade programs, carbon taxes, reporting and tracking programs, restriction of emissions, electric vehicle mandates, and combustion engine phaseouts. Any such legislation, regulations, or other regulatory initiatives, if enacted, or additional or increased taxes, assessments, or GHG-related fees on the Company's operations could lead to increased operating expenses or cause the Company to make significant capital investments for infrastructure modifications.

Enhanced focus on ESG matters could have an adverse effect on the Company's operations.

Enhanced focus on ESG matters related to, among other things, concerns raised by advocacy groups about climate change, hydraulic fracturing, waste disposal, oil spills, and explosions of natural gas transmission pipelines may lead to increased regulatory review, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines, and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens, increased risk of litigation, and adverse impacts on the Company's access to capital. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and regulatory approvals. Negative public perception could cause the permits or regulatory approvals the Company requires to be withheld, delayed, or burdened by requirements that restrict the Company's ability to profitably conduct its business.

The Company's estimates used in various scenario planning analyses could differ materially from actual results and could expose the Company to new or additional risks.

Given the dynamic nature of the Company's business, the Company generally performs biennial scenario analyses with five-year time horizons. When analyzing longer-term scenarios, the Company relies on external analysis for demand scenarios, carbon pricing, and comparison-pricing scenarios, which are then compared to the Company's internally prepared base-case pricing analysis averaged out to the year 2040. Given the numerous estimates that are required to run these scenarios, the Company's estimates could differ materially from actual results. The Company publicly discloses these metrics and its related assumptions and analysis in its sustainability reports. By electing to disclose these metrics, the Company may face increased scrutiny related to its ESG initiatives. Any harm to the Company's reputation resulting from publicly disclosing such metrics, expanding disclosures related to such metrics, or failing to achieve such metrics or abiding by such disclosures could adversely affect the Company's business, financial performance, and growth.

The treatment and disposal of produced water is becoming more highly regulated and restricted and could expose the Company to additional costs or limit certain operations.

The treatment and disposal of produced water is becoming more highly regulated and restricted. Regulators in some states, such as the Railroad Commission of Texas, have taken actions to limit disposal well activities (including orders to temporarily shut down or to curtail water injection) and to require the monitoring of seismic activity. While the Company remains focused on reusing or recycling water over disposal of water, the Company's costs for obtaining and disposing of water could increase significantly if reusing and recycling water becomes impractical. Further, compliance with reporting and environmental regulations governing the withdrawal, storage, use, and discharge of water and restrictions related to disposal

wells may increase the Company's operating costs or capital expenses or cause the Company to limit production, which could materially and adversely affect its business, results of operations, and financial conditions.

RISKS RELATED TO INTERNATIONAL OPERATIONS

International operations have uncertain political, economic, and other risks.

The Company's operations outside the U.S. are based primarily in Egypt and the U.K., with significant exploration, appraisal, and development activities offshore Suriname, which involve long-cycle projects with significant capital requirements and are subject to host-government approvals and fiscal and contractual frameworks that may evolve over time. On a barrel equivalent basis, approximately 38 percent of the Company's 2025 production was outside the U.S., and approximately 26 percent of the Company's estimated proved oil and gas reserves as of December 31, 2025, were located outside the U.S. As a result, a significant portion of the Company's production and resources are subject to the increased political and economic risks and other factors associated with international operations, including, but not limited to:

- strikes and civil unrest;
- war, acts of terrorism, expropriation and resource nationalization;
- forced renegotiation or modification of existing contracts, including through prospective or retroactive changes in laws and regulations;
- litigation, including as initiated by or otherwise involving non-governmental organizations;
- dependence on host-country approvals;
- local content requirements;
- vessel and equipment availability;
- import and export regulations;
- customs and port logistics;
- taxation policies and investment restrictions;
- price controls;
- exchange controls, currency fluctuations, devaluations, or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- constrained oil or natural gas markets dependent on demand in a single or limited geographical area;
- laws and policies of the U.S. affecting foreign trade, including trade sanctions and tariffs;
- the possibility of being subject to exclusive jurisdiction of foreign courts or tribunals in connection with legal disputes relating to licenses to operate and concession rights in countries where the Company currently operates;
- the possible inability to subject foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of courts in the U.S.; and
- difficulties in enforcing the Company's rights against a governmental agency or state-owned or government-controlled entities because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

In certain jurisdictions, governmental authorities may be exercised by multiple ministries, agencies, state-owned or government-controlled entities, or other governmental bodies with overlapping or evolving mandates. As a result, the Company may encounter inconsistent or shifting application of laws, regulations, contractual terms, or administrative requirements, including additional approvals, documentation requests, or procedural conditions. Compliance with such requirements may increase costs, delay operations, or affect project economics.

In addition, certain of the Company's frontier exploration activities may be subject to legal or administrative challenges in host jurisdictions. For example, in Uruguay, legal actions have recently been filed seeking to enjoin offshore drilling activities and to prevent the acquisition of seismic data. Although a request for injunctive relief was denied by a local court in one case, the underlying litigation remains pending and may be appealed or otherwise continued. If such challenges were successful, they could delay or impede the Company's exploration and appraisal activities in Uruguay, increase costs, or adversely affect the Company's ability to advance or realize value from those assets.

Foreign countries have occasionally asserted rights to oil and gas properties through border disputes. If a country claims superior rights to oil and gas leases or concessions granted to the Company by another country, the Company's interests could decrease in value or be lost. Even the Company's smaller international assets or exploration opportunities may affect its overall business and results of operations by distracting management's attention from its more significant assets. Certain regions of the world in which the Company operates have a history of political and economic instability. This instability could result in new governments or the adoption of new policies that might result in a substantially more hostile attitude toward foreign investments, such as the Company's, or to oil and gas operations generally. In an extreme case, such a change could result in termination of contract rights and expropriation of the Company's assets. This could adversely affect the Company's interests and its future profitability.

The impact that future terrorist attacks or regional hostilities, as have occurred in countries and regions in which the Company operates, may have on the oil and gas industry in general and on the Company's operations in particular is not known at this time. Uncertainty surrounding military strikes or a sustained military campaign may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants, and refineries, could be direct targets or indirect casualties of an act of terror or war. The Company may be required to incur significant costs in the future to safeguard its assets against terrorist activities.

A deterioration of conditions in Egypt or changes in the economic and political environment in Egypt could have an adverse impact on the Company's business.

Deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, new or increased taxes, fees, or levies, limitations affecting the repatriation or transfer of funds, expropriation of the Company's assets or resource nationalization, and/or forced renegotiation or modification of the Company's existing contracts with Egyptian General Petroleum Corporation (EGPC), or threats or acts of terrorism could materially and adversely affect the Company's business and operations. Additionally, previous deteriorations in the economic conditions in Egypt have led to a shortage of foreign currency, including U.S. dollars, resulting in a decline in the timeliness of payments from EGPC, and such declines may reoccur if conditions were to deteriorate again. If conditions were to deteriorate again in Egypt, then it could materially and adversely affect the Company's business, financial condition, and results of operations.

The Company's operations are sensitive to currency rate fluctuations.

The Company's operations are sensitive to fluctuations in foreign currency exchange rates, particularly among the U.S. dollar, the British pound, and the Egyptian pound. The Company's financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. Volatility in exchange rates may adversely affect the Company's results of operations, particularly through the weakening of the U.S. dollar relative to other currencies. For additional details, including discussion of foreign exchange contracts entered into by the Company, see the information set forth under "Foreign Currency Exchange Rate Risk" in Part II, Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

GENERAL RISK FACTORS

Certain anti-takeover provisions in the Company's charter and Delaware law could delay or prevent a hostile takeover.

The Company's charter authorizes the Board of Directors to issue preferred stock in one or more series and to determine the voting rights and dividend rights, dividend rates, liquidation preferences, conversion rights, redemption rights, including sinking fund provisions and redemption prices, and other terms and rights of each series of preferred stock. In addition, Delaware law imposes restrictions on mergers and other business combinations between the Company and any holder of 15 percent or more of APA's outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of the Company that would have been financially beneficial to APA's shareholders.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 1C. *CYBERSECURITY*

Risk Management and Strategy

The Company maintains a cybersecurity program that establishes safeguards for protecting the confidentiality, integrity, and availability of the Company's data, technology, and information systems, and the material risks associated with the threats identified from time to time under the cybersecurity program are incorporated into the Company's corporate risk register. The program includes general controls for managing changes in and access to the Company's information technology environment, cybersecurity awareness and training programs to help employees identify and mitigate against cybersecurity threats, cybersecurity incident response plans and third-party incident response retainers to help expedite the Company's response in the event of a cybersecurity incident, and guidelines regarding system vulnerability management, third-party threat intelligence, endpoint detection and response solutions, and network security measures.

The program also establishes protocols for identifying and managing material risks related to cybersecurity threats associated with the Company's use of third-party service providers. The Company monitors and oversees the material risks related to vulnerabilities, threats, and incidents impacting its third-party service providers via onboarding reviews, threat intelligence reports, and annual assessments. As an example of the Company's efforts to manage third-party cybersecurity risks, when third parties are engaged to provide software-as-a-service offerings, the Company's standard licensing terms require such third parties to utilize safeguards to protect the Company's data, in compliance with applicable standards from the International Organization for Standardization (ISO) regarding security techniques, and to notify the Company within 24 hours of becoming aware of a cybersecurity incident impacting the Company's data.

As of December 31, 2025, no risks from cybersecurity threats or incidents have materially affected or are reasonably likely to materially affect the Company's business strategy, results of operations, or financial condition.

Governance

The standing Cybersecurity Committee of the Company's Board of Directors assists with oversight of the Company's cybersecurity program and the material risks associated with the threats identified under the program. Given the Cybersecurity Committee's chair's previous military experience in positions relevant to information security and his NACD-sponsored CERT Certificate in Cybersecurity Oversight from Carnegie Mellon University's Software Engineering Institute, the committee benefits from his perspectives, skills, and training when reviewing and managing the Company's exposure to cybersecurity risks.

As stated in its charter, the Cybersecurity Committee's responsibilities include:

- providing oversight of the Company's cybersecurity policies, procedures, and plans, including the quality and effectiveness of the cybersecurity program;
- reviewing the Company's policies and procedures related to its preparation for, defense against, response to, and recovery from material cybersecurity incidents;
- reviewing with management the plans and methodology for periodic assessments of the Company's cybersecurity program by outside professionals, including the findings of such assessments and plans to remediate any material deficiencies identified by such assessments;
- overseeing the Company's management of risks related to its cybersecurity systems and processes;
- reviewing with management any cybersecurity insurance program the Company may procure, including with respect to coverage and limits; and
- overseeing the preparation of the Company's disclosures in its reports filed with the Securities and Exchange Commission relating to the Company's cybersecurity systems.

The Cybersecurity Committee also has authority to retain cybersecurity and other consultants and advisors to assist and advise the committee in its evaluation of the Company's cybersecurity program.

The Cybersecurity Committee receives regular reports from Company management regarding the Company's cybersecurity systems and programs, and the committee from time to time also receives updates from external cybersecurity specialists on cybersecurity trends and incidents, including those that may be particularly relevant to the Company's industry or operations. In addition, in exercising its oversight responsibilities, the Cybersecurity Committee has full access to Company management and may inquire into any matter that it considers to be of material concern to the committee or the full Board of Directors.

The Cybersecurity Committee reports regularly to the full Board of Directors, with respect to such matters as are relevant to the committee's discharge of its responsibilities and with respect to such recommendations as the committee deems appropriate for consideration by the Board of Directors. The Cybersecurity Committee also refers to the Audit Committee any matters that come to the attention of the Cybersecurity Committee that fall within the purview of the Audit Committee, including any matters related to the Company's internal control over financial reporting.

APA's Executive Vice President, Administration, is primarily responsible for identifying, assessing, and managing the material risks associated with cybersecurity threats and the incidents identified from time to time thereunder. He manages the Company's Information Security Team, which comprises cybersecurity professionals responsible for the day-to-day operation of the Company's cybersecurity program and managing the Company's threat intelligence, vulnerability management, forensics, and security architecture systems. APA's Executive Vice President, Administration, has 36 years of experience managing data and technology in the energy industry, including serving as the Company's CIO from 2015-2020. He receives regular updates from external cybersecurity specialists on emerging trends, threats, and technologies in the cybersecurity industry. The Executive Vice President, Administration, reports directly to APA's Chief Executive Officer and presents all relevant information to the Cybersecurity Committee.

Additionally, the Company's CyberSmart Defender Network, which is a multi-disciplinary team that includes representatives from across the Company's various departments, is responsible for raising awareness of cybersecurity issues, sharing learnings, and gaining access to advanced cybersecurity information and training.

Under the direction of the Executive Vice President, Administration, management's responsibilities with respect to the Company's cybersecurity program include (i) identifying and managing cybersecurity risks, (ii) coordinating cybersecurity incident response, (iii) assessing the health and maturity of the Company's cybersecurity policies, procedures, and plans, including the program, and (iv) reporting overall progress to the Cybersecurity Committee and to the full Board of Directors.

For additional information regarding relevant cybersecurity risks, see Item 1A—Risk Factors — "*A cyberattack targeting systems and infrastructure used by the Company or others in the oil and gas industry may adversely impact the Company's operations*."

ITEM 3. ***LEGAL PROCEEDINGS***

The information set forth under "Legal Matters" and "Environmental Matters" in Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K is incorporated herein by reference.

ITEM 4. ***MINE SAFETY DISCLOSURES***

None.

PART II

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

APA's common stock, par value $0.625 per share, is traded on the Nasdaq Global Select Market (Nasdaq) under the symbol "APA." The closing price of APA's common stock, as reported by the Nasdaq for January 31, 2026, was $26.41 per share. As of January 31, 2026, there were 353,251,476 shares of APA's common stock outstanding held by approximately 3,500 stockholders of record and 282,000 beneficial owners.

The Company has paid cash dividends on its common stock for 61 consecutive years through December 31, 2025. When, and if, declared by the Company's Board of Directors, future dividend payments will depend upon the Company's level of earnings, financial requirements, and other relevant factors.

Information concerning securities authorized for issuance under equity compensation plans is set forth under the caption "Equity Compensation Plan Information" in the proxy statement relating to the Company's 2026 annual meeting of stockholders, which is incorporated herein by reference.

Issuer Purchases of Equity Securities

The table below sets forth information with respect to shares of common stock repurchased by APA during 2025.

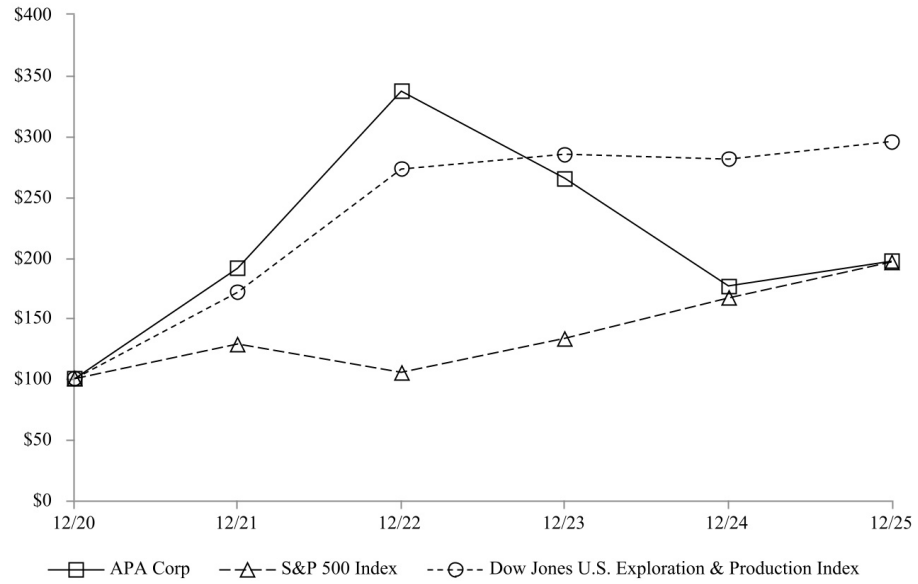
Period	Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 to January 31, 2025	1,670,918	$ 23.95	1,670,918	33,086,204
February 1 to February 29, 2025	2,470,913	22.34	2,470,913	30,615,291
March 1 to March 31, 2025	232,741	20.63	232,741	30,382,550
April 1 to April 30, 2025	603,233	16.59	603,233	29,779,317
May 1 to May 31, 2025	—	—	—	29,779,317
June 1 to June 30, 2025	2,096,211	19.09	2,096,211	27,683,106
July 1 to July 31, 2025	989,196	19.31	989,196	26,693,910
August 1 to August 31, 2025	1,214,309	19.92	1,214,309	25,479,601
September 1 to September 30, 2025	910,343	23.54	910,343	24,569,258
October 1 to October 31, 2025	997,815	23.53	997,815	23,571,443
November 1 to November 30, 2025	814,830	23.80	814,830	22,756,613
December 1 to December 31, 2025	890,475	25.23	890,475	21,866,138
Total	12,890,984	$ 21.73		

[1] During the fourth quarter of 2021, the Company's Board of Directors authorized the purchase of 40 million shares of the Company's common stock. During September of 2022, the Company's Board of Directors authorized the purchase of an additional 40 million shares of the Company's common stock. Shares may be purchased either in the open market or through privately negotiated transactions. The Company is not obligated to acquire any specific number of shares.

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's 500 Index (S&P 500 Index) and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from December 31, 2020, through December 31, 2025. The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among APA Corporation, the S&P 500 Index,
and the Dow Jones U.S. Exploration & Production Index



* $100 invested on 12/31/20 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	2020	2021	2022	2023	2024	2025
APA Corporation	$ 100.00	$ 190.76	$ 336.73	$ 265.27	$ 176.57	$ 196.71
S&P 500 Index	100.00	128.71	105.40	133.10	166.40	196.16
Dow Jones U.S. Exploration & Production Index	100.00	170.92	272.74	285.07	280.73	295.11

ITEM 6. ***SELECTED FINANCIAL DATA***

Omitted.

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

The following discussion relates to APA Corporation (APA or the Company) and its consolidated subsidiaries and should be read together in conjunction with the Company's Consolidated Financial Statements and accompanying notes included in Part IV, Item 15 of this Annual Report on Form 10-K, and the risk factors and related information set forth in Part I, Item 1A and Part II, Item 7A of this Annual Report on Form 10-K. This section of this Annual Report on Form 10-K generally discusses 2025 and 2024 items and year-to-year comparisons between 2025 and 2024. Discussions of 2023 items and year-to-year comparisons between 2024 and 2023 that are not included in this Annual Report on Form 10-K are incorporated by reference to "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of APA Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2024 (filed with the SEC on February 28, 2025).

Overview

APA is an independent energy company that owns subsidiaries that explore for, develop, and produce crude oil, natural gas, and natural gas liquids (NGLs). The Company's business has oil and gas operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea (North Sea). APA also has active development, exploration, and appraisal operations ongoing in Suriname, as well as exploration interests in Uruguay, Alaska, and other international locations that may, over time, result in reportable discoveries and development opportunities. As a holding company, APA Corporation's primary assets are its ownership interests in its consolidated subsidiaries.

APA believes energy underpins global progress, and the Company wants to be a part of the solution as society works to meet growing global demand for reliable and affordable energy. APA strives to meet those challenges while creating value for all its stakeholders.

Uncertainties in the global supply chain and financial markets impact oil supply and demand and contribute to commodity price volatility. These uncertainties include the impacts of ongoing international conflicts, inflation, current and potential tariffs or other trade barriers, global trade policies and disputes, and actions taken by foreign oil and gas producing nations, including OPEC+. Despite these uncertainties, the Company is focused on its longer-term objectives: (1) to remain committed to providing affordable, reliable, and responsibly produced energy; (2) to deliver top operational performance across safety, environmental responsibility, execution, and risk management measures; (3) to maintain financial discipline by managing costs, protecting the balance sheet to underpin the generation of cash flow in excess of its upstream exploration, appraisal, and development capital program that can be directed to debt reduction, share repurchases, and other return of capital to its shareholders; and (4) to build and grow a diverse and balanced high-quality portfolio with scale through acquisitions, exploration, and organic opportunities.

The Company closely monitors hydrocarbon pricing fundamentals to reallocate capital as part of its ongoing planning process. APA's diversified asset portfolio and operational flexibility provide the Company the ability to timely respond to price volatility and effectively manage its investment programs.

With increasing uncertainty around commodity prices during the first quarter of 2025, the Company announced a significant cost reduction initiative to drive sustainable cost savings for the long-term. This included reducing the Company's overhead costs, addressing the capital cost structure for its drilling, completions, and facility investments, and improving efficiencies of day-to-day field operating practices. The Company achieved $350 million in annualized savings across G&A, LOE, and capital as of year-end 2025. The Company expects $450 million of annualized savings by the end of 2026.

Additionally, the Company remains committed to its capital return framework for equity holders to participate more directly and materially in cash returns.

- The Company believes returning 60 percent of free cash flow through dividends and share repurchases creates a good balance for providing near-term cash returns to shareholders while still recognizing the importance of longer-term balance sheet strengthening.
- The Company paid a quarterly dividend of $0.25 per share on its common stock during 2025.
- Beginning in the fourth quarter of 2021 and through the end of 2025, the Company has repurchased 98.2 million shares of the Company's common stock. As of December 31, 2025, the Company had remaining authorization to repurchase up to 21.9 million shares under the Company's share repurchase program.

Financial and Operational Highlights

During 2025, the Company reported net income attributable to common stock of $1.4 billion, or $3.99 per diluted share, compared to net income of $804 million, or $2.27 per diluted share, in 2024. The increase in net income during 2025 was primarily the result of by $1.1 billion of impairments recorded in 2024, which included oil and gas property impairments of $796 million in the North Sea and $315 million in the U.S. The Company also recorded lower operating expenses in 2025 compared to the prior-year period, the result of focused cost-reduction efforts undertaken in 2025.

The Company generated $4.5 billion of cash from operating activities in 2025, which was $925 million or 26 percent higher than 2024. APA's higher operating cash flows for 2025 were primarily driven by the collection of outstanding receivables, lower overall expenses, and timing of other working capital items. The Company repurchased 12.9 million shares of its common stock for $280 million and paid $360 million in dividends to APA common stockholders during 2025. The Company ended the year with approximately $4.5 billion of debt, a reduction of approximately $1.6 billion from the end of 2024.

Key operational highlights for the year include:

United States

- Daily boe production from the Company's U.S. assets, which increased 2 percent from 2024, accounted for 62 percent of the Company's worldwide production during 2025. The Company averaged approximately seven drilling rigs in the U.S. during the year, including four rigs in the Midland Basin and three rigs in the Delaware Basin, and drilled and brought online 154 operated wells in 2025. The Company's core Permian Basin development program continues to consistently attract the largest portion of capital investment.
- In the Permian Basin, the Company is currently operating five rigs, reflecting improved capital efficiency while sustaining the pace of wells brought online. The Company anticipates continuing this level of activity to deliver 2026 oil production consistent with the prior year. Should oil prices decline, the Company may moderate activity in 2026 and further reduce capital spending.
- The Company holds approximately 750,000 MMBtu/d of firm capacity on various pipelines. As of December 31, 2025, the Company had open basis swap contracts which purchased Waha and sold NYMEX Henry Hub on approximately one-third of its firm transport capacity for 2026, thereby locking in a significant portion of cash flows associated with its gas marketing activities for the near term. Refer to Note 4—Derivative Instruments and Hedging Activities for further discussion of these basis swap agreements.
- During the first quarter of 2025, the Company and its partners announced preliminary results of an exploratory well in Alaska, confirming the successful discovery of a reservoir. A successful flow test of the well was announced in April, with the well averaging 2,700 b/d during the final flow period. The Company continues to evaluate the data from the well to determine next steps, and further appraisal drilling will determine the ultimate size of the discovery. The Company holds a 50 percent ownership interest in the project.

International

- During the fourth quarter of 2024, the Company entered into a new gas sales agreement with the Government of Egypt. Effective January 2025, substantially all of the Company's natural gas production was sold to EGPC under the terms of this agreement. The agreement provides the Company with enhanced economic terms that support increased natural gas exploration and development activity and the potential addition of significant new drilling inventory with expected returns comparable to those of the Company's oil program.
- In Egypt, the Company averaged 12 drilling rigs and drilled 71 new productive wells during 2025. During the same period, the Company averaged 19 workover rigs as it continues to align its drilling and workover activity with a goal of driving improved capital efficiency. The 2025 gross and net production from the Company's Egypt assets decreased 2 percent and 6 percent, respectively, from 2024.
- During the third quarter of 2025, the Government of Egypt awarded the Company an additional two million net exploration acres in the Western Desert. This new acreage expands on the Company's existing position in the country. In addition to a signature bonus of $25 million, the Company has committed to a drilling program on the acreage that the Company believes it will be able to meet in the normal course of operations. The Government also helped facilitate significant payments in the third quarter of 2025, nearly eliminating past due receivables.

For a more detailed discussion related to the Company's various geographic segments, refer to "Exploration and Production—Operating Areas" set forth in Part I, Items 1 and 2 of this Annual Report on Form 10-K.

Acquisition and Divestiture Activity

Over the Company's history, it has repeatedly demonstrated the ability to capitalize quickly and decisively on changes in its industry and economic conditions. A key component of this strategy is to continuously review and optimize APA's portfolio of assets in response to these changes. Most recently, the Company has completed a series of acquisitions and divestitures designed to enhance the Company's portfolio and monetize nonstrategic assets in order to allocate resources to more impactful exploration and development opportunities. These acquisitions and divestitures include:

- *Sale of Non-core Permian Basin Properties* During the second quarter of 2025, the Company completed the sale of all of its New Mexico Permian assets. The assets had a carrying value of $282 million and associated retirement obligation of $9 million, which were exchanged for total cash consideration of $571 million, inclusive of post-closing adjustments.
- *Egypt Acreage Acquisition* During the third quarter of 2025, the Government of Egypt awarded the Company an additional two million net exploration acres in the Western Desert. In addition to a signature bonus of $25 million, the Company has committed to a drilling program on the acreage that the Company believes it will be able to meet in the normal course of operations.
- *Callon Petroleum Company Acquisition* On April 1, 2024, APA completed its acquisition of Callon Petroleum Company (Callon) in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's debt (the Callon acquisition). The acquired assets included approximately 120,000 net acres in the Delaware Basin and 25,000 net acres in the Midland Basin.
- *Sale of Non-core Permian Basin Properties* On December 31, 2024, APA completed the sale of non-core producing properties in the Permian Basin that had a carrying value of $1.1 billion and associated asset retirement obligation of $224 million for total cash proceeds of $869 million after closing adjustments. The properties are located in the Central Basin Platform, Texas and New Mexico Shelf, and Northwest Shelf.
- *Non-core Acreage Divestiture* During 2024, the Company completed the sale of non-core acreage in the East Texas Austin Chalk and Eagle Ford plays that had a carrying value of $347 million for aggregate cash proceeds of $255 million and the assumption of asset retirement obligations of $42 million.
- *Mineral Rights Divestiture* During 2024, the Company also completed the sale of non-core mineral and royalty interests in the Permian Basin that had a carrying value of $71 million for approximately $394 million subject to post-closing adjustments.
- *Sales of Kinetik Shares* During 2023, the Company sold a portion of its Kinetik Holdings Inc. (Kinetik) Class A Common Stock (Kinetik Shares) for cash proceeds of $228 million. During the first quarter of 2024, the Company sold its remaining Kinetik Shares for cash proceeds of $428 million. On April 3, 2024, the Company's designated director resigned from the Kinetik board of directors.

For detailed information regarding APA's acquisitions and divestitures, refer to Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Results of Operations

Oil, Natural Gas, and Natural Gas Liquids Production Revenues

The Company's production revenues and respective contribution to total revenues by country are as follows:

	For the Year Ended December 31,					
	2025		2024		2023	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
	($ in millions)					
Oil Revenues:						
United States	$ 3,010	52 %	$ 3,572	51 %	$ 2,241	37 %
Egypt[1]	2,177	37 %	2,620	38 %	2,683	45 %
North Sea	622	11 %	774	11 %	1,073	18 %
Total[1]	$ 5,809	100 %	$ 6,966	100 %	$ 5,997	100 %
Natural Gas Revenues:						
United States	$ 193	25 %	$ 126	22 %	$ 297	34 %
Egypt[1]	460	60 %	313	53 %	346	39 %
North Sea	117	15 %	145	25 %	237	27 %
Total[1]	$ 770	100 %	$ 584	100 %	$ 880	100 %
NGL Revenues:						
United States	$ 616	95 %	$ 617	96 %	$ 480	94 %
North Sea	34	5 %	29	4 %	28	6 %
Total[1]	$ 650	100 %	$ 646	100 %	$ 508	100 %
Oil and Gas Revenues:						
United States	$ 3,819	53 %	$ 4,315	53 %	$ 3,018	41 %
Egypt[1]	2,637	36 %	2,933	36 %	3,029	41 %
North Sea	773	11 %	948	11 %	1,338	18 %
Total[1]	$ 7,229	100 %	$ 8,196	100 %	$ 7,385	100 %

(1) Includes revenues attributable to a noncontrolling interest in Egypt.

Production

The following table presents production volumes by country:

	For the Year Ended December 31,				
	2025	Increase (Decrease)	2024	Increase (Decrease)	2023
Oil Volumes – b/d:					
United States[5]	125,526	(2)%	128,531	63%	78,889
Egypt[3][4]	87,719	(1)%	89,027	—%	89,129
North Sea	24,186	(8)%	26,340	(24)%	34,728
Total	237,431	(3)%	243,898	20%	202,746
Natural Gas Volumes – Mcf/d:					
United States[5]	514,502	6%	483,446	7%	452,281
Egypt[3][4]	350,774	21%	291,011	(11)%	325,778
North Sea	31,318	(22)%	39,986	(20)%	50,284
Total	896,594	10%	814,443	(2)%	828,343
NGL Volumes – b/d:					
United States[5]	76,264	3%	73,877	17%	62,997
North Sea	1,256	5%	1,201	(3)%	1,240
Total	77,520	3%	75,078	17%	64,237
BOE per day:[1]					
United States[5]	287,539	2%	282,983	30%	217,266
Egypt[3][4]	146,182	6%	137,529	(4)%	143,425
North Sea[2]	30,662	(10)%	34,204	(23)%	44,349
Total	464,383	2%	454,716	12%	405,040

(1) The table shows production on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the price ratio between the two products.

(2) Average sales volumes from the North Sea were 31,168 boe/d, 33,954 boe/d, and 45,476 boe/d for 2025, 2024, and 2023, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings.

(3) Gross oil, natural gas, and NGL production in Egypt were as follows:

	2025	2024	2023
Oil (b/d)	125,511	137,150	141,985
Natural Gas (Mcf/d)	486,462	443,551	500,080

(4) Includes net production volumes per day attributable to a noncontrolling interest in Egypt of:

	2025	2024	2023
Oil (b/d)	29,267	29,698	29,739
Natural Gas (Mcf/d)	117,035	97,078	108,703

(5) Production volumes per day in the Company's Wildfire field were as follows:

	2025	2024	2023
Oil (b/d)	29,023	19,970	15,644
Natural Gas (Mcf/d)	52,650	41,136	29,537
NGL (b/d)	10,127	7,540	5,622

Pricing

The following table presents pricing information by country:

	For the Year Ended December 31,				
	2025	Increase (Decrease)	2024	Increase (Decrease)	2023
Average Oil Price - Per barrel:					
United States	$ 65.71	(13)%	$ 75.92	(2)%	$ 77.84
Egypt	67.97	(15)%	80.41	(2)%	82.47
North Sea	69.31	(14)%	80.74	(2)%	82.75
Total	66.92	(14)%	78.08	(3)%	80.72
Average Natural Gas Price - Per Mcf:					
United States	$ 1.02	44%	$ 0.71	(61)%	$ 1.80
Egypt	3.59	22%	2.94	1%	2.91
North Sea	12.03	11%	10.84	(17)%	13.02
Total	2.36	20%	1.97	(32)%	2.91
Average NGL Price - Per barrel:					
United States	$ 22.13	(3)%	$ 22.83	9%	$ 20.85
North Sea	43.59	(8)%	47.59	—%	47.77
Total	22.71	(3)%	23.37	8%	21.54

Crude Oil Prices A substantial portion of the Company's crude oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of the Company's control. Average realized crude oil prices for 2025 were down 14 percent compared to 2024, a direct result of decreasing benchmark oil prices over the past year. Crude oil prices realized in 2025 averaged $66.92 per barrel.

Continued volatility in the commodity price environment reinforces the importance of the Company's asset portfolio. While the market price received for natural gas varies among geographic areas, crude oil tends to trade within a global market. Prices for all types and grades of crude oil generally move in the same direction.

Natural Gas Prices Natural gas, which currently has a limited global transportation system, is subject to price variances based on local supply and demand conditions. The Company's primary markets include North America, Egypt, and the U.K. An overview of the market conditions in the Company's primary gas-producing regions follows:

- The Company sells its U.S. natural gas production at liquid index sales points within the U.S., at either monthly or daily index-based prices. The Company's U.S. realizations averaged $1.02 per Mcf in 2025, a 44 percent increase from an average of $0.71 per Mcf in 2024.
- In Egypt, substantially all of the Company's 2025 natural gas production is sold to EGPC pursuant to a gas sales agreement that establishes pricing based on a minimum realized price of $2.65 per MMBtu, with the potential for higher pricing on incremental volumes when pre-determined production thresholds are met. The gas sales agreement was effective beginning January 2025. In the periods prior to the current agreement, the natural gas production in Egypt was primarily sold to EGPC at an industry-pricing formula of $2.65 per MMBtu. Overall, the Company's Egypt operations averaged $3.59 per Mcf in 2025, a 22 percent increase from an average of $2.94 per Mcf in 2024.
- Natural gas from the North Sea Beryl field is processed through the SAGE gas plant. The gas is sold to a third party at the St. Fergus entry point of the national grid on a National Balancing Point index price basis. The Company's North Sea operations averaged $12.03 per Mcf in 2025, a 11 percent increase from an average of $10.84 per Mcf in 2024.

NGL Prices The Company's U.S. NGL production, which accounted for 98 percent of the Company's total 2025 NGL production, is sold under contracts with prices at market indices based on Gulf Coast supply and demand conditions, less the costs for transportation and fractionation, or on a weighted-average sales price received by the purchaser.

Crude Oil Revenues

Crude oil revenues for 2025 totaled $5.8 billion, a $1.2 billion decrease from the 2024 total of $7.0 billion. A 14 percent decrease in average realized prices reduced 2025 revenues by $996 million compared to 2024, while a 3 percent lower average daily production decreased revenues by $161 million. Average daily production in 2025 was 237 Mb/d, with prices averaging $66.92 per barrel. Crude oil sales accounted for 80 percent of the Company's 2025 oil and gas production revenues and 51 percent of its worldwide production.

The Company's worldwide crude oil production decreased 6 Mb/d compared to 2024, primarily a result of the sale of non-core assets in the U.S. and natural production decline, mostly offset by drilling activity in the Permian Basin.

Natural Gas Revenues

Natural gas revenues for 2025 totaled $770 million, a $186 million increase from the 2024 total of $584 million. A 20 percent increase in average realized prices increased 2025 revenues by $118 million compared to 2024, while 10 percent higher average daily production increased revenues by $68 million. Average daily production in 2025 was 897 MMcf/d, with prices averaging $2.36 per Mcf. Natural gas sales accounted for 11 percent of the Company's 2025 oil and gas production revenues and 32 percent of its worldwide production.

The Company's worldwide natural gas production increased 82 MMcf/d compared to 2024, primarily a result of successful drilling activity in Egypt and the Permian Basin. These increases were offset by natural production decline in the U.S. and North Sea, the sale of non-core assets in the U.S., curtailment of volumes at Alpine High in response to extreme Waha basis differentials, and operational downtime in the U.S.

NGL Revenues

NGL revenues for 2025 totaled $650 million, a $4 million increase from the 2024 total of $646 million. A 3 percent higher average daily production increased 2025 revenues by $22 million compared to 2024, while a 3 percent decrease in average realized prices decreased revenues by $18 million. Average daily production in 2025 was 78 Mb/d, with prices averaging $22.71 per barrel. NGL sales accounted for 9 percent of the Company's 2025 oil and gas production revenues and 17 percent of its worldwide production.

The Company's worldwide NGL production increased 2 Mb/d compared to 2024, primarily a result of increased drilling activity in the Permian Basin, offset by natural production decline, the sale of non-core assets in the U.S., and curtailment of volumes at Alpine High in response to extreme Waha basis differentials

Purchased Oil and Gas Sales

Purchased oil and gas sales represent volumes primarily attributable to domestic gas purchases that were sold by the Company to fulfill natural gas takeaway obligations and delivery commitments. Sales related to purchased volumes increased $150 million for the year ended December 31, 2025 to $1.7 billion from $1.5 billion in 2024. Purchased oil and gas sales were partially offset by associated purchase costs of $1.1 billion and $1.0 billion for the years ended December 31, 2025 and 2024, respectively. The increase in purchased oil and gas sales was primarily driven by higher natural gas prices at various delivery locations.

Operating Expenses

The table below presents a comparison of the Company's operating expenses for the years ended December 31, 2025, 2024, and 2023. All operating expenses include costs attributable to a noncontrolling interest in Egypt.

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Lease operating expenses	$ 1,504	$ 1,690	$ 1,436
Gathering, processing, and transmission	424	432	334
Purchased oil and gas costs	1,070	1,047	742
Taxes other than income	229	270	207
Exploration	131	313	195
General and administrative	350	372	351
Transaction, reorganization, and separation	102	168	15
Depreciation, depletion, and amortization:			
Oil and gas property and equipment	2,275	2,235	1,500
Gathering, processing, and transmission assets	6	6	6
Other assets	23	25	34
Asset retirement obligation accretion	158	148	116
Impairments	44	1,129	61
Financing costs, net	113	367	312

Lease Operating Expenses (LOE)

LOE includes several key components, such as direct operating costs, repairs and maintenance, and workover costs. Direct operating costs generally trend with commodity prices and are impacted by the type of commodity produced and the location of properties (i.e., offshore, onshore, remote locations, etc.). Fluctuations in commodity prices impact operating cost elements both directly and indirectly. They directly impact costs such as power, fuel, and chemicals, which are commodity price based. Commodity prices also affect industry activity and demand, thus indirectly impacting the cost of items such as rig rates, labor, boats, helicopters, materials, and supplies. Crude oil, which accounted for 51 percent of the Company's total 2025 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties.

During 2025, LOE decreased $186 million, or 11 percent, compared to 2024. On a per-boe basis, LOE decreased $1.30, or 13 percent, compared to 2024, from $10.16 per boe to $8.86 per boe. The decrease in absolute costs was primarily driven by lower workover activity, continued cost reduction efforts in all operating areas, and the sale of non-core assets in the Permian Basin. This decrease was partially offset by a full year of operating costs associated with the Callon transaction.

Gathering, Processing, and Transmission (GPT)

GPT expenses include amounts paid to third-party carriers for gathering and transmission services for the Company's upstream natural gas production. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Third-party processing and transmission costs	$ 424	$ 409	$ 225
Midstream service costs – Kinetik	—	23	109
Upstream processing and transmission costs	424	432	334
Total Gathering, processing, and transmission	$ 424	$ 432	$ 334

GPT costs decreased $8 million compared to 2024, primarily the result of decreased oil production volumes in the U.S. and lower average transportation rates.

Purchased Oil and Gas Costs

Purchased oil and gas costs increased $23 million for the year ended December 31, 2025, to $1.1 billion from $1.0 billion in 2024. The increase is primarily driven by gas volumes purchased at higher prices during 2025 compared to the prior-year period coupled with activity associated with the Callon acquisition.

Taxes Other Than Income

Taxes other than income primarily consist of severance taxes on onshore properties and in state waters off the coast of the U.S. and ad valorem taxes on U.S. properties. Severance taxes are generally based on a percentage of oil and gas production revenues. The Company is also subject to a variety of other taxes, including U.S. franchise taxes.

Taxes other than income decreased $41 million compared to 2024, primarily from lower severance taxes driven by lower oil prices and lower ad valorem taxes.

Exploration Expenses

Exploration expenses include unproved leasehold impairments, exploration dry hole expense, geological and geophysical expenses, and the costs of maintaining and retaining unproved leasehold properties. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Unproved leasehold impairments	$ 2	$ 35	$ 22
Dry hole expenses	67	201	92
Geological and geophysical expenses	8	21	19
Exploration overhead and other	54	56	62
Total Exploration	$ 131	$ 313	$ 195

Exploration expenses decreased $182 million compared to 2024, primarily the result of higher dry hole expenses in Suriname and Alaska and unproved leasehold impairments during 2024. Dry hole expenses in 2025 primarily relate to increased exploration drilling in Egypt.

General and Administrative (G&A) Expenses

G&A expenses in 2025 decreased $22 million compared to 2024. Focused cost-reduction efforts on personnel and other overhead expenses drove a decrease of $67 million, which more than offset higher stock compensation expense of $45 million primarily driven from an increase in the Company's stock price during 2025. For additional information on the Company's stock compensation, refer to Note 12—Capital Stock in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Transaction, Reorganization, and Separation (TRS) Costs

TRS costs decreased $66 million compared to 2024, primarily a result of transaction costs related to the Callon acquisition during 2024, partially offset by employee separations and other cost-saving reorganization initiatives during 2025.

Depreciation, Depletion and Amortization (DD&A)

DD&A expenses on the Company's oil and gas property for the year ended December 31, 2025 increased $40 million compared to 2024. The Company's oil and gas property DD&A rate remained relatively flat in 2025 compared to 2024, from $13.44 per boe to $13.41 per boe, mainly the result of negative gas price-related reserve revisions in the U.S. Permian Basin offset by non-core asset divestitures.

Impairments

During 2025, the Company recorded $44 million of impairments, which included $18 million of non-operated proved oil and gas property in Egypt, approximately $18 million related to the sale of an office building in the U.S., a $1 million impairment for GPT facilities in Egypt, and $7 million of inventory impairments in the North Sea. During 2024, the Company recorded $1.1 billion of impairments, which included $796 million of oil and gas property impairments in the North Sea, a $315 million impairment of certain oil and gas properties in the U.S. held-for-sale, and $18 million of inventory impairments in the North Sea and U.S.

Financing Costs, Net

Financing costs incurred during 2025, 2024, and 2023 comprised the following:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Interest expense	$ 323	$ 402	$ 351
Amortization of debt issuance costs	7	6	4
Capitalized interest	(45)	(29)	(24)
Gain on extinguishment of debt	(147)	—	(9)
Interest income	(25)	(12)	(10)
Total Financing costs, net	$ 113	$ 367	$ 312

Net financing costs during 2025 decreased $254 million compared to 2024, primarily driven by gains on extinguishment of debt from the Company's cash tender purchases in early 2025 and lower overall interest expense from lower outstanding long-term debt balances.

Provision for Income Taxes

For the year ended December 31, 2025, income tax expense increased by $682 million to $1.1 billion from $417 million in 2024. The Company's 2025 and 2024 effective income tax rates were primarily impacted by taxes related to foreign operations.

On January 10, 2023, Finance Act 2023 was enacted, receiving Royal Assent and included amendments to the Energy (Oil and Gas) Profits Levy Act of 2022 (the Energy Profits Levy), increasing the levy from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023 through March 31, 2028. On March 20, 2025, Finance Act 2025 was enacted, receiving Royal Assent, and included further amendments to the Energy Profits Levy, increasing the levy from a 35 percent rate to a 38 percent rate, among other changes, effective for the period of November 1, 2024 through March 31, 2030. Under U.S. GAAP, the financial statement impact of new legislation is recorded in the period of enactment. As a result, the Company recorded tax expense of $78 million and $174 million related to the change in tax law in 2025 and 2023, respectively.

On August 16, 2022, the U.S. enacted the Inflation Reduction Act of 2022 (IRA). The IRA includes a new 15 percent corporate alternative minimum tax (CAMT) on applicable corporations with an average annual adjusted financial statement income that exceeds $1.0 billion for any three consecutive years preceding the tax year at issue. The CAMT is effective for tax years beginning after December 31, 2022. The Company became an applicable corporation subject to CAMT beginning on January 1, 2024. On September 12, 2024, the U.S. Department of Treasury and the Internal Revenue Service released proposed regulations relating to the application and implementation of CAMT. In 2025, the Company recorded a current tax benefit of $71 million related to the 2024 return-to-accrual adjustment, with an offsetting deferred tax expense of the same amount for the change in CAMT credits.

On July 4, 2025, the U.S. enacted the One Big Beautiful Bill Act of 2025 (OBBBA). Among other changes, the OBBBA expanded and made permanent 100 percent bonus depreciation for eligible assets acquired and placed in service after January 19, 2025, and aligned the treatment of intangible drilling costs for CAMT purposes with regular tax treatment starting in 2026. OBBBA did not have a material impact on total tax expense for the year ended December 31, 2025, as impacts to current tax expense are offset by impacts to deferred tax expense. In 2025, the law change resulted in a current tax benefit of $42 million fully offset by a deferred tax expense of the same amount.

On September 30, 2025, the Internal Revenue Service issued further interim guidance on CAMT. Among other changes, the guidance provided for a reduction to CAMT related to net operating loss utilization for regular federal income tax purposes. This guidance did not have a material impact on total tax expense for the year ended December 31, 2025, as impacts to current tax expense are offset by impacts to deferred tax expense. In 2025, the guidance resulted in a current tax benefit of $72 million, fully offset by a deferred tax expense of the same amount.

In December 2021, the Organisation for Economic Co-operation and Development issued Pillar Two Model Rules introducing a new global minimum tax of 15 percent on a country-by-country basis, with certain aspects effective in certain jurisdictions on January 1, 2024. Although the Company continues to monitor enacted legislation to implement these rules in countries where the Company could be impacted, the Company does not expect that the Pillar Two framework will have a material impact on its consolidated financial statements.

Deferred tax assets are recorded for future deductible amounts and certain other tax benefits, such as net operating losses, tax credits and other tax attributes, provided that the Company assesses the utilization of such assets to be “more likely than not.” The Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to realize the existing deferred tax assets. Based on this assessment, the Company has recorded valuation allowances for certain net operating losses, foreign tax credits and capital loss carryforwards that it does not believe are more likely than not to be realized.

During the fourth quarter of 2023, as a result of increases in projections of future taxable income and the absence of objective negative evidence such as a cumulative loss in recent years, the Company determined there was sufficient positive evidence to release a majority of the U.S. valuation allowance, which resulted in a non-cash deferred income tax benefit of $1.7 billion.

For additional information regarding income taxes, refer to Note 9—Income Taxes in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company and its subsidiaries are subject to U.S. federal income tax as well as income or capital taxes in various states and foreign jurisdictions. The Company’s tax reserves are related to tax years that may be subject to examination by the relevant taxing authority. The Company is under audit by the Internal Revenue Service and in various state and foreign jurisdictions as part of its normal course of business.

Capital and Operational Outlook

The Company continues to prudently manage its capital program against a volatile price environment and the effects of global inflation and rising interest rates. Despite these uncertainties, the Company is focused on its longer-term objectives: (1) to remain committed to providing affordable, reliable, and responsibly produced energy; (2) to deliver top operational performance across safety, environmental responsibility, execution, and risk management measures; (3) to maintain financial discipline by managing costs, protecting the balance sheet to underpin the generation of cash flow in excess of its upstream exploration, appraisal, and development capital program that can be directed to debt reduction, share repurchases, and other return of capital to its shareholders; and (4) to build and grow a diverse and balanced high-quality portfolio with scale through acquisitions, exploration, and organic opportunities.

In 2026, the Company plans to invest approximately $2.1 billion in upstream capital investment. The Company is committed to maintaining a safe, steady, and efficient level of activity as part of its planned capital investment program. For 2026, the Company will continue to budget its capital program at levels to fund activity necessary to offset inherent declines in production and proved oil and natural gas reserves, subject to prevailing commodity prices. Future rig activity levels and drilling targets will be dependent on the success of the Company's drilling program and its ability to add reserves economically.

In the Permian Basin, the Company is currently operating five rigs, reflecting improved capital efficiency. The Company anticipates continuing this level of activity to deliver consistent year-over-year oil production. Should oil prices decline, the Company may moderate activity in 2026 and further reduce capital spending. The Company is planning a 12-rig program in Egypt, with five to six rigs dedicated to gas exploration. This activity set translates to a combined development capital budget for the Permian Basin and Egypt of approximately $1.8 billion. In addition, the Company will invest approximately $70 million for exploration in Alaska and Suriname and $230 million for Suriname development.

This investment profile underscores the progress the Company has made on capital efficiency over the course of 2025. At current strip pricing, the Company expects to generate significant cash flow over this capital activity budget. The Company's current commitment to return capital to shareholders through a mix of dividends and share buybacks remains unchanged.

Capital Resources and Liquidity

Operating cash flows are the Company's primary source of liquidity. The Company's short-term and long-term operating cash flows are impacted by highly volatile commodity prices, as well as production costs and sales volumes. Significant changes in commodity prices impact the Company's revenues, earnings, and cash flows. These changes potentially impact the Company's liquidity if costs do not trend with sustained decreases in commodity prices. Historically, costs have trended with commodity prices, albeit on a lag. Sales volumes also impact cash flows; however, they have a less volatile impact in the short term.

The Company's long-term operating cash flows are dependent on reserve replacement and the level of costs required for ongoing operations. Cash investments are required to fund activity necessary to offset the inherent declines in production and proved crude oil and natural gas reserves. Future success in maintaining and growing reserves and production is highly dependent on the success of the Company's drilling program and its ability to add reserves economically. Changes in commodity prices also impact estimated quantities of proved reserves.

The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2025, 2024, and 2023, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 16—Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company believes its available liquidity and capital resource alternatives, combined with proactive measures to adjust its capital budget to reflect volatile commodity prices and anticipated operating cash flows, will be adequate to fund short-term and long-term operations, including the Company's capital development program, repayment of debt maturities, payment of dividends, share buy-back activity, and amounts that may ultimately be paid in connection with commitments and contingencies.

The Company may also elect to utilize available cash on hand, committed borrowing capacity, access to both debt and equity capital markets, or proceeds from the sale of nonstrategic assets for all other liquidity and capital resource needs.

For additional information, refer to Part I, Items 1 and 2—Business and Properties and Part I, Item 1A—Risk Factors of this Annual Report on Form 10-K.

Sources and Uses of Cash

The following table presents the sources and uses of the Company's cash and cash equivalents for the years presented:

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 4,545	$ 3,620	$ 3,129
Fixed-rate debt borrowings	846	—	—
Proceeds from asset divestitures	611	1,609	29
Proceeds from term loan facility	—	1,500	—
Proceeds from sale of Kinetik shares	—	428	228
Total Sources of Cash and Cash Equivalents	6,002	7,157	3,386
Uses of Cash and Cash Equivalents:			
Additions to oil and gas property[(1)]	2,740	2,851	2,313
Acquisition of Delaware Basin properties	—	—	24
Leasehold and property acquisitions	26	60	20
Payments on term loan facility	900	600	—
Payments on commercial paper and revolving credit facilities, net	333	40	194
Payments on Callon Credit Agreement	—	472	—
Payments on fixed-rate debt	1,016	1,641	65
Dividends paid to APA common stockholders	360	353	308
Distributions to noncontrolling interest	430	268	238
Treasury stock activity, net	280	246	329
Other, net	26	88	53
Total Uses of Cash and Cash Equivalents	6,111	6,619	3,544
Increase (decrease) in cash and cash equivalents	$ (109)	$ 538	$ (158)

(1) The table presents capital expenditures on a cash basis; therefore, the amounts may differ from those discussed elsewhere in this Annual Report on Form 10-K, which include accruals.

Sources of Cash and Cash Equivalents

Net Cash Provided by Operating Activities Operating cash flows are the Company's primary source of capital and liquidity and are impacted, both in the short term and the long term, by volatile commodity prices. The factors that determine operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, exploratory dry hole expense, asset impairments, asset retirement obligation (ARO) accretion, and deferred income tax expense.

Net cash provided by operating activities for the year ended December 31, 2025 totaled $4.5 billion, up $925 million from the year ended December 31, 2024, primarily due to collection of outstanding receivables, lower overall expenses, and timing of other working capital items.

For a detailed discussion of commodity prices, production, and operating expenses, refer to "Results of Operations" in this Item 7. For additional detail on the changes in operating assets and liabilities and the non-cash expenses that do not impact net cash provided by operating activities, refer to the Statement of Consolidated Cash Flows in the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Fixed-Rate Debt Borrowings During the year ended December 31, 2025, the Company issued new notes for proceeds of $846 million, after deducting discounts and loan costs, to fund in part APA's purchase of Apache notes in APA's cash tender offers.

Proceeds from Asset Divestitures The Company received $611 million and $1.6 billion in proceeds from the divestiture of certain non-core assets during the years ended December 31, 2025 and 2024, respectively. For more information regarding the Company's divestitures, refer to Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Uses of Cash and Cash Equivalents

Additions to Oil & Gas Property Exploration and development cash expenditures were $2.7 billion and $2.9 billion for the years ended December 31, 2025 and 2024, respectively. The decrease in capital investment is reflective of the Company's plan to streamline capital deployment and the sale of certain non-core assets and leasehold in the Permian Basin. The Company operated an average of 19 drilling rigs during 2025, compared to an average of 22 drilling rigs during 2024.

Leasehold and Property Acquisitions During 2025 and 2024, the Company completed other leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $26 million and $60 million, respectively.

Payments on Term Loan Facility During 2025 and 2024, the Company made payments of $900 million and $600 million, respectively, on its syndicated term loan credit agreement and fully repaid the term loans. For additional details of this credit agreement, see "*Unsecured Committed Term Loan Facility"* in the Liquidity section below.

Payments on Commercial Paper and Revolving Credit Facilities, Net During 2025, the Company made net payments of $333 million on its commercial paper and U.S. dollar denominated syndicated credit facility borrowings. As of December 31, 2025, there were no outstanding borrowings under the Company's commercial paper or syndicated credit facilities.

Payments on Fixed-Rate Debt During 2025, the Company settled its private exchange and cash tender offers for certain notes and debentures of Apache and made open market repurchases of indenture debt of APA and Apache, and Apache redeemed certain notes for aggregate cash payments of $1.0 billion, reflecting principal amounts, discount to par, and associated fees.

During 2024, the Company financed Callon's repayment pursuant to Callon's cash tender offers for, and redemptions of all senior notes issued under Callon's indentures for an aggregate cash payment of $1.6 billion, reflecting principal amounts, premium to par, and associated fees.

Dividends Paid to APA Common Stockholders The Company paid $360 million and $353 million during the years ended December 31, 2025 and 2024, respectively, for dividends on its common stock.

Distributions to Noncontrolling Interest Sinopec holds a one-third minority participation interest in the Company's oil and gas operations in Egypt. The Company paid $430 million and $268 million during the years ended December 31, 2025 and 2024, respectively, in cash distributions to Sinopec.

Treasury Stock Activity, Net During 2025, the Company repurchased 12.9 million shares at an average price of $21.73 per share totaling $280 million, and as of December 31, 2025, the Company had remaining authorization to repurchase 21.9 million shares. During 2024, the Company repurchased 9.2 million shares at an average price of $26.83 per share totaling $246 million.

Liquidity

The following table presents a summary of the Company's key financial indicators as of December 31:

	2025	2024
	(In millions)	
Cash and cash equivalents	$ 516	$ 625
Total debt – APA and Apache	4,493	6,044
Total equity	7,003	6,362
Available committed borrowing capacity under syndicated credit facilities	4,020	2,966

Cash and Cash Equivalents As of December 31, 2025, the Company had $516 million in cash and cash equivalents. The majority of the Company's cash is invested in highly liquid, investment-grade instruments with maturities of three months or less at the time of purchase.

Debt As of December 31, 2025, the Company had $4.5 billion in total debt outstanding, which consisted of notes and debentures of APA and Apache, and finance lease obligations. As of December 31, 2025, current debt included $2 million of finance lease obligations and $211 million of APA and Apache notes coming due within the next year.

Indenture Debt Activity On August 20, 2025, Apache redeemed the outstanding $51 million principal amount of 4.625% Notes due 2025, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date.

During 2025, the Company purchased in the open market and had canceled indebtedness issued under indentures of APA and Apache in an aggregate principal amount of $122 million for an aggregate purchase price of $112 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $13 million. The Company recognized a $12 million gain on these repurchases. The repurchases were partially financed by APA's borrowing under the Company's commercial paper program. Refer to discussion of APA exchange and tender offers for Apache indenture debt below for further details regarding the gain on extinguishment of debt during the quarter ended March 31, 2025.

The indentures under which APA has issued senior notes and debentures restrict it from issuing or guaranteeing certain secured indebtedness, consolidating with or merging into another person, and transferring or leasing its properties and assets as an entirety or substantially as an entirety to any person. Indentures of APA and Apache do not contain prepayment obligations in the event of a decline in credit ratings. In connection with the transactions summarized below under "APA Exchange and Tender Offers for Apache Indenture Debt," Apache's indentures were amended on January 10, 2025, to remove certain restrictive and reporting covenants, except those applicable to certain notes maturing in 2026 and 2027.

APA Exchange and Tender Offers for Apache Indenture Debt On January 10, 2025, the Company settled its private exchange and cash tender offers for certain notes and debentures issued by Apache under its indentures. The Company also then settled its private offering of new notes to fund in part its purchase of Apache notes in APA's cash tender offers. In settling these offerings pursuant to their respective terms:

- APA issued new notes and debentures under its indentures in aggregate principal amounts of (i) $2.5 billion in exchange for Apache notes and debentures tendered and accepted in APA's exchange offers, (ii) $203 million in exchange for Apache notes tendered in the cash tender offers in excess of the stated maximum purchase amount or series caps, and (iii) $850 million in the new notes offering, comprised of $350 million aggregate principal amount of APA's 6.10% Notes due 2035 and $500 million aggregate principal amount of APA's 6.75% Notes due 2055.
- In addition to issuing the APA notes in the exchange offers, APA paid a total of $2.5 million in cash as part of the exchange consideration.
- APA paid a total of $869 million in cash in the tender offers (comprised of tender offer consideration, exchange consideration for tendered notes exchanged, early participation premium, and accrued interest) for the aggregate $1 billion in principal amount of Apache notes tendered and accepted in the cash tender offers. The Company recognized a gain of $135 million on these purchases, including broker fees and loan costs.
- Net proceeds from the sale of the notes in APA's new notes offering, after deducting the initial purchasers' discounts and estimated offering expenses, were approximately $839 million and used to fund in part APA's purchase of Apache notes in APA's cash tender offers.
- Each series of APA notes and debentures issued in settlement of the exchange and tender offers had the same interest rate, maturity date, and interest payment dates and the same optional redemption prices (if any) as the corresponding series of Apache notes and debentures for which they were exchanged.
- Each series of APA notes and debentures issued in settlement of the exchange and tender offers and new notes offering were fully and unconditionally guaranteed by Apache until the first time that the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures was less than $1 billion, which occurred in May 2025, after which Apache's guarantees were terminated in accordance with their terms on May 16, 2025.
- APA entered into two registration rights agreements pursuant to which APA agreed to register under the Securities Act of 1933, as amended, the notes and debentures that APA issued in the exchange and tender offers and new notes offering (collectively, the Unregistered Notes). On September 18, 2025, APA settled registered exchange offers for the Unregistered Notes, issuing registered notes and debentures in the same aggregate principal amount as the Unregistered Notes accepted for exchange and canceled and otherwise on terms substantially identical in all material respects to the applicable series of Unregistered Notes. Of the $3.6 billion aggregate principal amount of Unregistered Notes covered by the registered exchange offers, 99 percent was exchanged for registered notes and debentures, and the remaining Unregistered Notes remained outstanding.

Unsecured 2025 Committed Bank Credit Facilities On January 15, 2025, the Company entered into two unsecured syndicated credit agreements for general corporate purposes:

- One agreement is denominated in US dollars (the 2025 USD Agreement) and provides for an unsecured five-year revolving credit facility for loans and letters of credit, with aggregate commitments of US$2.0 billion (including a letter of credit subfacility of up to US$750 million, of which US$250 million currently is committed). APA may increase commitments up to an aggregate US$2.5 billion by adding new lenders or obtaining the consent of any increasing existing lenders. This facility matures in January 2030, subject to the Company's two, one-year extension options.

- The second agreement is denominated in pounds sterling (the 2025 GBP Agreement) and provides for an unsecured five-year revolving credit facility, with aggregate commitments of £1.5 billion for loans and letters of credit. This facility matures in January 2030, subject to the Company's two, one-year extension options.

Apache guaranteed obligations under each of the 2025 USD Agreement and 2025 GBP Agreement (each, a 2025 Agreement) effective until the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures first was less than US$1.0 billion, which occurred in May 2025, after which Apache's guarantees were terminated in accordance with their terms on May 16, 2025.

The 2025 Agreements replaced on substantially the same terms two syndicated credit agreements that the Company entered in April 2022, one of which was denominated in US dollars with aggregate commitments of US$1.8 billion (the 2022 USD Agreement) and second of which was denominated in pounds sterling with aggregate commitments of £1.5 billion (the 2022 GBP Agreement). On January 15, 2025, the Company terminated commitments under both the 2022 USD Agreement and 2022 GBP Agreement in connection with entry into the 2025 Agreements.

As of December 31, 2025, there were no borrowings or letters of credit outstanding under the 2025 USD Agreement and no borrowings and an aggregate £1.0 million in letters of credit outstanding under the 2025 GBP Agreement. As of December 31, 2024, there were $10 million of borrowings and no letters of credit outstanding under the 2022 USD Agreement, and no borrowings and an aggregate £303 million in letters of credit outstanding under the 2022 GBP Agreement.

All borrowings under the 2025 USD Agreement bear interest at one of two per annum rate options selected by the borrower, being either an alternate base rate (as defined), plus a margin varying from 0.0% to 0.675% (Base Rate Margin), or an adjusted term SOFR rate (as defined), plus a margin varying from 1.00% to 1.675% (Applicable Margin). All borrowings under the 2025 GBP Agreement bear interest with respect to any business day at an adjusted rate per annum determined by reference to the Sterling Overnight Index Average with respect to such business day published by the Bank of England, plus the Applicable Margin.

Each 2025 Agreement also requires the borrower to pay quarterly (i) a facility fee on total commitments at a per annum rate that varies from 0.125% to 0.325% and (ii) a commission on the face amount of each outstanding letter of credit at a per annum rate equal to the Applicable Margin then in effect. Customary letter of credit fronting fees and other charges are payable to issuing banks.

Margins and facility fees are at varying rates per annum determined by reference to the senior, unsecured, non-credit enhanced, long-term indebtedness for borrowed money of APA (Long-Term Debt Rating). The current Base Rate Margin is 0.30%, the Applicable Margin is 1.30%, and the facility fee is 0.20%.

Borrowers under each 2025 Agreement, which include certain subsidiaries of APA, may borrow, prepay, and reborrow loans and obtain letters of credit, and APA may obtain letters of credit for the account of its subsidiaries, in each case subject to representations and warranties, covenants, and events of default, such as:

- A financial covenant requires APA to maintain an adjusted debt-to-capital ratio of not greater than 65% at the end of any fiscal quarter.

- A negative covenant restricts the ability of APA and its subsidiaries to create liens securing debt on their hydrocarbon-related assets, with customary exceptions and exceptions for liens on subsidiary assets located outside of the U. S. and Canada; liens on assets also are permitted if debt secured thereby does not exceed 15% of APA's consolidated net tangible assets.

- Negative covenants restrict APA's ability to merge with another entity unless it is the surviving entity, a borrower's disposition of substantially all of its assets, prohibitions on the ability of certain subsidiaries to make payments to borrowers, and guarantees by APA or certain subsidiaries of debt of non-consolidated entities in excess of the stated threshold.

- Lenders may accelerate payment maturity and terminate lending and issuance commitments for nonpayment and other breaches; if a borrower or certain subsidiaries defaults on other indebtedness in excess of the stated threshold, has any unpaid, non-appealable judgment against it for payment of money in excess of the stated threshold, or has specified pension plan liabilities in excess of the stated threshold; or APA undergoes a specified change in control. Such acceleration and termination are automatic upon specified insolvency events of a borrower or certain subsidiaries.

The 2025 Agreements do not require collateral, do not have a borrowing base, do not permit lenders to accelerate maturity or refuse to lend based on unspecified material adverse changes, and do not have borrowing restrictions or prepayment obligations in the event of a decline in credit ratings.

The Company was in compliance with the terms of the 2025 Agreements as of December 31, 2025.

Uncommitted Lines of Credit Each of the Company and Apache, from time to time, has and uses uncommitted credit and letter of credit facilities for working capital and credit support purposes. As of December 31, 2025 and 2024, there were no outstanding borrowings under these facilities. As of December 31, 2025, there were £901 million and $10 million in letters of credit outstanding under these facilities. As of December 31, 2024, there were £640 million and $11 million in letters of credit outstanding under these facilities.

Commercial Paper Program The Company has a commercial paper program under which it from time to time may issue in private placements exempt from registration under the Securities Act short-term unsecured promissory notes (CP Notes) up to a maximum aggregate face amount of $2.0 billion outstanding at any time. The program was established in December 2023, and the maximum aggregate face amount of CP Notes issuable thereunder was increased to $2.0 billion from $1.8 billion on June 20, 2025. The maturities of the CP Notes may vary but may not exceed 397 days from the date of issuance. Outstanding CP Notes are supported by available borrowing capacity under the Company's committed revolving credit facilities for general corporate purposes, which as of December 31, 2025, included the $2.0 billion 2025 USD Agreement.

Payment of the CP Notes was unconditionally guaranteed on an unsecured basis by Apache, such guarantee effective until the first time that the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures was less than US$1.0 billion, which occurred in May 2025, after which Apache's guarantees were terminated in accordance with their terms on June 20, 2025.

The CP Notes are sold under customary market terms in the U.S. commercial paper market at a discount from par or at par and bear interest at rates determined at the time of issuance.

As of December 31, 2025, the Company had no CP Notes outstanding. As of December 31, 2024, the Company had $323 million in aggregate face amount of CP Notes outstanding, which was classified as long-term debt.

Unsecured Committed Term Loan Facility On January 30, 2024, APA entered into a syndicated credit agreement providing for committed senior unsecured delayed-draw term loans to APA, the proceeds of which could be used to refinance certain indebtedness of Callon.

On April 1, 2024, APA acquired Callon and borrowed $1.5 billion under this credit agreement maturing April 1, 2027, of which $900 million remained outstanding as of December 31, 2024. APA fully prepaid this credit agreement on March 10, 2025. The repayment was partially financed with borrowings under APA's 2025 USD Agreement and commercial paper program.

Contractual Obligations

Purchase Obligations From time to time, the Company enters into agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms. These include minimum commitments associated with take-or-pay contracts, NGL processing agreements, drilling work program commitments and agreements to secure capacity rights on third-party pipelines. As of December 31, 2025, the Company had contractual obligations totaling $971 million, of which $778 million is related to U.S. firm transportation contracts, $133 million is related to U.S. purchase obligations, $28 million is related to the merged concession agreement with the EGPC, and $32 million is related to other items.

Leases In the normal course of business, the Company enters into various lease agreements for real estate, drilling rigs, vessels, aircrafts, and equipment related to its exploration and development activities, which are typically classified as operating leases under the provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 842 (Leases). As of December 31, 2025, the Company had net undiscounted minimum commitments of $428 million and $34 million for operating and finance leases, respectively.

Interest Expense Future interest payments based on the current maturity dates of the Company's fixed-rate notes and debentures as of December 31, 2025 are approximately $3.7 billion.

For additional information regarding these obligations, refer to Note 8—Debt and Financing Costs and Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

For information regarding the Company's liability for dismantlement, abandonment, and restoration costs of oil and gas properties, refer to Note 7—Asset Retirement Obligation in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

For information regarding pension or postretirement benefit obligations, refer to Note 11—Retirement and Deferred Compensation Plans in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. The Company's management believes that it has adequately reserved for its contingent obligations, including approximately $2 million for environmental remediation and approximately $23 million for various contingent legal liabilities. For a detailed discussion of the Company's environmental and legal contingencies and other commitments, please see Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

With respect to oil and gas operations in the Gulf of America, the Bureau of Ocean Energy Management (BOEM) issued a Notice to Lessees (NTL No. 2016-N01) significantly revising the obligations of companies operating in the Gulf of America to provide supplemental assurances of performance with respect to plugging, abandonment, and decommissioning obligations associated with wells, platforms, structures, and facilities located upon or used in connection with such companies' oil and gas leases. While the NTL was paused in mid-2017 and is currently listed on BOEM's website as "rescinded," if reinstated, the NTL will likely require that the Company provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to the Company's current ownership interests in various Gulf of America leases. Additionally, the Company is not able to predict the effect that these changes might have on counterparties to which the Company has sold Gulf of America assets or with whom the Company has joint ownership. Such changes could cause the bonding obligations of such parties to increase substantially, thereby causing a significant impact on the counterparties' solvency and ability to continue as a going concern.

Potential Decommissioning Obligations on Sold Properties

The Company's subsidiaries have potential exposure to future obligations related to divested properties. The Company has divested various leases, wells, and facilities located in the Gulf of America (GOA) where the purchasers typically assume all obligations to plug, abandon, and decommission the associated wells, structures, and facilities acquired. One or more of the counterparties in these transactions could, either as a result of the severe decline in oil and natural gas prices or other factors related to the historical or future operations of their respective businesses, face financial problems that may have a significant impact on their solvency and ability to continue as a going concern. If a purchaser of such GOA assets becomes the subject of a case or proceeding under relevant insolvency laws or otherwise fails to perform required abandonment obligations, APA's subsidiaries could be required to perform such actions under applicable federal laws and regulations. In such event, such subsidiaries may be forced to use available cash to cover the costs of such liabilities and obligations should they arise.

In 2013, Apache sold its GOA Shelf operations and properties and its GOA operating subsidiary, GOM Shelf LLC (GOM Shelf) to Fieldwood Energy LLC (Fieldwood). Fieldwood assumed the obligation to decommission the properties held by GOM Shelf and the properties acquired from Apache and its other subsidiaries (collectively, the Legacy GOA Assets). On February 14, 2018, Fieldwood filed for (and subsequently emerged from) Chapter 11 bankruptcy protection. On August 3, 2020, Fieldwood filed for (and subsequently emerged from) Chapter 11 bankruptcy protection for a second time. Upon emergence from this second bankruptcy, the Legacy GOA Assets were separated into a standalone company, which was subsequently merged into GOM Shelf. Under GOM Shelf's limited liability company agreement, the proceeds of production of the Legacy GOA Assets are to be used to fund the operation of GOM Shelf and the decommissioning of Legacy GOA Assets. The decommissioning obligations for the Legacy GOA Assets are partially secured by a trust account of which Apache is a beneficiary and which is funded by net profits interests (NPIs) depending on future oil prices. In addition, after such sources have been exhausted, Apache agreed upon resolution of GOM Shelf's second bankruptcy to loan GOM Shelf up to $400 million to perform decommissioning, with such loans and related obligations secured by first and prior liens on the Legacy GOA Assets.

By letter dated April 5, 2022 (replacing two earlier letters) and by subsequent letter dated March 1, 2023, GOM Shelf notified the Bureau of Safety and Environmental Enforcement (BSEE) that it was unable to fund the decommissioning obligations that it was obligated to perform on certain of the Legacy GOA Assets. As a result, Apache and other current and former owners in these assets have received orders from BSEE and demands from third parties to decommission certain of the Legacy GOA Assets included in GOM Shelf's notifications to BSEE. Apache expects to receive similar orders and demands on the other Legacy GOA Assets included in GOM Shelf's notification letters. Apache has also received orders to decommission other Legacy GOA Assets that were not included in GOM Shelf's notification letters. Further, Apache anticipates that GOM Shelf may send additional such notices to BSEE in the future and that it may receive additional orders from BSEE requiring it to decommission other Legacy GOA Assets.

As of December 31, 2025, the Company recorded an asset of $40 million representing the remaining amount the Company expects to be reimbursed from remaining security related to these decommissioning costs. Of the total asset recorded as of December 31, 2025, $21 million is reflected under the caption "Decommissioning security for sold Gulf of America properties," and $19 million is reflected under "Other current assets" in the Company's consolidated balance sheet.

As of December 31, 2025, Apache estimates that its potential liability to fund the remaining decommissioning of Legacy GOA Assets and assets previously sold to other operators ranges from $0.9 billion to $1.2 billion on an undiscounted basis. Management does not believe any specific estimate within this range is a better estimate than any other. Accordingly, the Company recorded contingent liabilities in the amounts of $881 million and $1.0 billion as of December 31, 2025, and December 31, 2024, respectively. Of the total liability recorded as of December 31, 2025, $782 million is reflected under the caption "Decommissioning contingency for sold Gulf of America properties" and $99 million is reflected under "Other current liabilities" in the Company's consolidated balance sheet. Changes in significant assumptions impacting Apache's estimated liability, including expected well decommissioning spread rates, derrick barge rates, planned abandonment logistics, and future cash flows of GOM Shelf, could result in a liability in excess of the amount accrued.

The Company recognized $60 million of "Gains on previously sold Gulf of America properties" during 2025 to reflect the net impact of decreased estimated decommissioning costs of Legacy GOA Assets which BSSE may order the Company to decommission. The Company recognized losses on previously sold Gulf of America properties of $273 million and $212 million during 2024 and 2023, respectively, in the Company's statement of consolidated operations.

Insurance Program

The Company maintains insurance policies that include coverage for physical damage to its assets, general liabilities, workers' compensation, employers' liability, sudden and accidental pollution, and other risks. The Company's insurance coverage is subject to deductibles or retentions that it must satisfy prior to recovering on insurance. Additionally, the Company's insurance is subject to policy exclusions and limitations. There is no assurance that insurance will adequately protect the Company against liability from all potential consequences and damages. Further, the Company does not have coverage in place for a variety of other risks including Gulf of America named windstorm and business interruption.

The Company purchases multi-year political risk insurance from highly-rated insurers covering a portion of its investments in Egypt for losses arising from confiscation, nationalization, and expropriation risks.

Future insurance coverage for the Company's industry could increase in cost and may include higher deductibles or retentions or a change in policy limit or additional exclusions or limitations. In addition, some forms of insurance may become unavailable or unavailable on terms economically acceptable.

Service agreements, including drilling contracts, generally indemnify the Company for injuries and death of the service provider's employees, as well as subcontractors hired by the service provider, and damages to their respective property.

Critical Accounting Estimates

The Company prepares its financial statements and accompanying notes in conformity with accounting principles generally accepted in the U.S., which require management to make estimates and assumptions about future events that affect reported amounts in the financial statements and the accompanying notes. The Company identifies certain accounting policies involving estimation as critical accounting estimates based on, among other things, their impact on the portrayal of the Company's financial condition, results of operations, or liquidity, as well as the degree of difficulty, subjectivity, and complexity in their deployment. Critical accounting estimates address accounting matters that are inherently uncertain due to unknown future resolution of such matters. Management routinely discusses the development, selection, and disclosure of each critical accounting estimate. The following is a discussion of the Company's most critical accounting estimates.

Long-Lived Asset Impairments

Long-lived assets used in operations, including proved oil and gas properties and GPT assets, are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. If there is an indication that the carrying amount of an asset group may not be recovered, the asset is assessed by management through an established process in which changes to significant assumptions such as prices, volumes, and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is assessed by management using the income approach.

Under the income approach, the fair value of each asset group is estimated based on the present value of expected future cash flows. The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, the success of future exploration for and development of unproved reserves, expected throughput volumes for GPT assets, discount rates, and other variables. Key assumptions used in developing a discounted cash flow model described above include estimated quantities of crude oil and natural gas reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating and administrative costs. The Company discounts the resulting future cash flows using a discount rate believed to be consistent with those applied by market participants.

To assess the reasonableness of our fair value estimate, when available, management uses a market approach to compare the fair value to similar assets. This requires management to make certain judgments about the selection of comparable assets, recent comparable asset transactions, and transaction premiums.

Although the fair value estimate of each asset group is based on assumptions believed to be reasonable, those assumptions are inherently unpredictable and uncertain, and actual results could differ from the estimate. Negative revisions of estimated reserves quantities, increases in future cost estimates, divestiture of a significant component of the asset group, or sustained decreases in crude oil or natural gas prices could lead to a reduction in expected future cash flows and possibly an additional impairment of long-lived assets in future periods.

For discussion of these impairments, see "Fair Value Measurements" of Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business. The amount of goodwill or bargain purchase gain recognized, if any, is determined based on the consideration transferred compared to the amounts of the identifiable net assets acquired on the acquisition date.

The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company's assets and liabilities and tax-related carryforwards at the merger date, although such estimates may change in the future as additional information becomes known.

In estimating the fair values of assets acquired and liabilities assumed, the Company has made various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved oil and natural gas properties. The fair value of proved oil and natural gas properties as of the acquisition date were estimated using the income approach where fair value was determined based on the expected future cash flows from estimated proved oil, natural gas, and NGL reserves and related discounted future net cash flows as of that date. Significant inputs to the fair value estimate included estimates of future production volumes, future operating and development costs, future commodity prices, and a weighted average cost of capital discount rate.

The estimates used in determining fair values are based on assumptions believed to be reasonable but which are inherently uncertain. Accordingly, actual results may differ from the projected results used to determine fair value. Historically there has been volatility in oil, natural gas, and NGL prices, and estimates of such future prices are inherently imprecise. Additionally, the actual timing of the production could be different than projected volumes as of the acquisition date.

Reserves Estimates

Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations.

Despite judgment involved in these engineering estimates, the Company's reserves are used throughout its financial statements. For example, since the Company uses the units-of-production method to amortize its oil and gas properties, the quantity of reserves could significantly impact DD&A expense. A material adverse change in the estimated volumes of reserves could result in property impairments. Finally, these reserves are the basis for the Company's supplemental oil and gas disclosures. For more information regarding the Company's supplemental oil and gas disclosures, refer to Note 16—Supplemental Oil and Gas Disclosures (Unaudited) in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Reserves are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous twelve months, held flat for the life of the production, except where prices are defined by contractual arrangements. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation.

The Company has elected not to disclose probable and possible reserves or reserve estimates in this filing.

Offshore Decommissioning Contingency

The Company has potential exposure to future obligations related to divested properties. For information regarding estimated potential decommissioning obligations on sold properties, please refer to "Potential Decommissioning Obligations on Sold Properties" above and in Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

The Company's estimated contingent obligation is primarily associated with the abandonment, removal and decommissioning of offshore wells and platforms in the Gulf of America. Estimating any future obligation requires significant judgment. The Company utilizes actual abandonment and decommissioning costs incurred as the basis to estimate the expected cash outflows for future obligations. Actual costs incurred often vary based on each structure's condition, depth-of-water, type, and other similar factors, which are key considerations when estimating the remaining well and platform decommissioning obligation. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, and safety considerations. Changes in significant assumptions or the regulatory framework impacting the Company's estimated liability could result in a liability in excess of the amount accrued.

Asset Retirement Obligation (ARO)

The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms in the North Sea. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, and safety considerations.

ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties and other long-lived assets. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Income Taxes

The Company's oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions worldwide. The Company records deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in its financial statements and tax returns. Management routinely assesses the ability to realize the Company's deferred tax assets. If management concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

ITEM 7A.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about the Company's exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil, gas, and NGL prices, interest rates, or foreign currency and adverse governmental actions. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how the Company views and manages its ongoing market risk exposures.

Commodity Price Risk

The Company's revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices the Company receives for its crude oil, natural gas, and NGLs, which have historically been very volatile because of unpredictable events such as economic growth or retraction, weather, political climate, and global supply and demand. The Company continually monitors its market risk exposure, as oil and gas supply and demand are impacted by uncertainties in the commodity and financial markets, actions taken by foreign oil and gas producing nations, including OPEC+, global inflation, and other current events.

The Company's average crude oil price realizations decreased 14 percent to $66.92 per barrel in 2025 from $78.08 per barrel in 2024. The Company's average natural gas price realizations increased 20 percent to $2.36 per Mcf in 2025 from $1.97 per Mcf in 2024. The Company's average NGL price realizations decreased 3 percent to $22.71 per barrel in 2025 from $23.37 per barrel in 2024. Based on average daily production for 2025, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $87 million, a $0.10 per Mcf change in the weighted average realized natural gas price would have increased or decreased revenues for the year by approximately $33 million, and a $1.00 per barrel change in the weighted average realized NGL price would have increased or decreased revenues for the year by approximately $28 million.

The Company periodically enters into derivative positions on a portion of its projected crude oil and natural gas production through a variety of financial and physical arrangements intended to manage fluctuations in cash flows resulting from changes in commodity prices. Such derivative positions may include the use of futures contracts, swaps, and/or options. The Company does not hold or issue derivative instruments for trading purposes. As of December 31, 2025, the Company had open natural gas derivatives not designated as cash flow hedges in a net liability position with a fair value of $77 million. A 10 percent increase in natural gas prices would decrease the liability by approximately $5 million, while a 10 percent decrease in prices would increase the liability by approximately $6 million. Refer to Note 4—Derivative Instruments and Hedging Activities in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report Form 10-K for notional volumes and terms with the Company's derivative contracts.

Interest Rate Risk

As of December 31, 2025, the Company had $4.5 billion, net, in outstanding notes and debentures, all of which was fixed-rate debt, with a weighted average interest rate of 5.66 percent. Although near-term changes in interest rates may affect the fair value of fixed-rate debt, such changes do not expose the Company to the risk of earnings or cash flow loss associated with that debt.

The Company is also exposed to interest rate risk related to its interest-bearing cash and cash equivalents balances and amounts outstanding under its term loan facility, commercial paper program, and syndicated credit facilities. As of December 31, 2025, the Company had approximately $516 million in cash and cash equivalents, approximately 95 percent of which was invested in money market funds and short-term investments with major financial institutions. As of December 31, 2025, there were no borrowings outstanding under the Company's term loan facility, commercial paper program, and syndicated revolving credit facilities. Changes in the interest rate applicable to short-term investments, term loan facility, and commercial paper program are expected to have an immaterial impact on earnings and cash flows but could impact interest costs associated with future debt issuances or any future borrowings.

Foreign Currency Exchange Rate Risk

The Company's cash activities relating to certain international operations is based on the U.S. dollar equivalent of cash flows measured in foreign currencies. The Company's North Sea production is sold under U.S. dollar contracts, while the majority of costs incurred are paid in British pounds. The Company's Egypt production is sold under U.S. dollar contracts, and the majority of costs incurred are denominated in U.S. dollars. Transactions denominated in British pounds are converted to U.S. dollar equivalents based on the average exchange rates during the period. The Company monitors foreign currency exchange rates of countries in which it is conducting business and may, from time to time, implement measures to protect against foreign currency exchange rate risk.

Foreign currency gains and losses also arise when monetary assets and monetary liabilities denominated in foreign currencies are translated at the end of each month. Foreign currency gains and losses are included as either a component of "Other, net" under "Revenues and Other" or, as is the case when the Company re-measures its foreign tax liabilities, as a component of the Company's provision for income tax expense on the statement of consolidated operations. Foreign currency net gain or loss would not be material from a 10 percent weakening or strengthening, respectively, in the British pound as of December 31, 2025.

The Company is subject to increased foreign currency risk associated with the effects of decommissioning obligations in the North Sea. The Company has periodically entered into foreign exchange contracts in order to minimize the impact of fluctuating exchange rates for the British pound on the Company's operations. Subsequent to December 31, 2025, the Company entered into outstanding foreign exchange contracts with a total notional amount of £120 million to reduce its exposure to fluctuating foreign exchange rates for the British pound.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

The financial statements and supplementary financial information required to be filed under this Item 8 are presented on pages F-1 through F-59 in Part IV, Item 15 of this Annual Report on Form 10-K and are incorporated herein by reference.

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

The financial statements for the fiscal years ended December 31, 2025, 2024, and 2023, included in this Annual Report on Form 10-K, have been audited by Ernst & Young LLP, independent registered public accounting firm, as stated in their audit report appearing herein. There have been no changes in or disagreements with the accountants during the periods presented.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

John J. Christmann IV, the Company's Chief Executive Officer, in his capacity as principal executive officer, and Ben C. Rodgers, the Company's Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of December 31, 2025, the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation and as of the date of that evaluation, these officers concluded that the Company's disclosure controls and procedures were effective, providing effective means to ensure that the information the Company is required to disclose under applicable laws and regulations is recorded, processed, summarized, and reported within the time periods specified in the Commission's rules and forms and accumulated and communicated to the Company's management, including its principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

The Company periodically reviews the design and effectiveness of its disclosure controls, including compliance with various laws and regulations that apply to its operations, both inside and outside the United States. The Company makes modifications to improve the design and effectiveness of our disclosure controls, and may take other corrective action, if the Company's reviews identify deficiencies or weaknesses in its controls.

Management's Annual Report on Internal Control Over Financial Reporting; Attestation Report of the Registered Public Accounting Firm

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to the "Report of Management on Internal Control Over Financial Reporting," included on Page F-1 in Part IV, Item 15 of this Annual Report on Form 10-K.

The independent auditors attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to the "Report of Independent Registered Public Accounting Firm," included on Page F-2 through F-5 in Part IV, Item 15 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There was no change in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

During the three months ended December 31, 2025, none of the Company's officers or directors adopted, modified, or terminated any "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement" (as such term is defined in Item 408 of Regulation S-K promulgated under the Securities Act).

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

Not applicable.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information set forth under the captions "Nominees for Election as Directors," "Information about Our Executive Officers," "Securities Ownership and Principal Holders," "Additional Information—Future Shareholder Proposals and Director Nominations," "Corporate Governance—Board Committees, Meetings, and Responsibilities," and "Corporate Governance—Insider Trading Policy" in the proxy statement relating to the Company's 2026 annual meeting of shareholders (the Proxy Statement) is incorporated herein by reference.

Code of Conduct

In accordance with Rule 5610 of the Nasdaq, the Company maintains a code of conduct for its directors, officers, and employees. The Company's Code of Conduct was adopted by the Company's Board of Directors in March 2021 and subsequently amended in December 2024 (as amended, the Code of Conduct). The Code of Conduct also meets the requirements of a code of ethics under Item 406 of Regulation S-K. You can access the Code of Conduct on the Governance page of the Company's website at www.apacorp.com. Any shareholder who so requests may obtain a printed copy of the Code of Conduct by submitting a request to the Company's corporate secretary at the address on the cover of this Annual Report on Form 10-K. Changes in and waivers to the Code of Conduct for the Company's directors, chief executive officer and certain senior financial officers will be posted on the Company's website within four business days and maintained for at least 12 months. Information on the Company's website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report on Form 10-K.

ITEM 11. *EXECUTIVE COMPENSATION*

The information set forth under the captions "Compensation Discussion and Analysis (CD&A)," "Summary Compensation Table," "Grants of Plan-Based Awards Table," "Outstanding Equity Awards at Fiscal Year-End Table," "Option Exercises and Stock Vested Table," "Non-Qualified Deferred Compensation Table," "Potential Payments upon Termination or Change in Control," "Director Compensation Table," "CEO Pay Ratio," "Compensation Committee Interlocks and Insider Participation," "Pay versus Performance," "Equity Award Grant Practices," and "Compensation Committee Report" in the Proxy Statement is incorporated herein by reference.

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

The information set forth under the captions "Securities Ownership and Principal Holders" and "Equity Compensation Plan Information" in the Proxy Statement is incorporated herein by reference.

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

The information set forth under the captions "Certain Business Relationships and Transactions" and "Director Independence" in the Proxy Statement is incorporated herein by reference.

ITEM 14. *PRINCIPAL ACCOUNTING FEES AND SERVICES*

The information set forth under the caption "Ratification of Auditor Appointment" in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. ***EXHIBITS, FINANCIAL STATEMENT SCHEDULES***

(a) Documents included in this report:

1. Financial Statements

Report of management on internal control over financial reporting	F-1
Report of independent registered public accounting firm (PCAOB ID: 42)	F-2
Report of independent registered public accounting firm (PCAOB ID: 42)	F-3
Statement of consolidated operations for each of the three years in the period ended December 31, 2025	F-5
Statement of consolidated comprehensive income for each of the three years in the period ended December 31, 2025	F-6
Statement of consolidated cash flows for each of the three years in the period ended December 31, 2025	F-7
Consolidated balance sheet as of December 31, 2025 and 2024	F-8
Statement of consolidated changes in equity and noncontrolling interest for each of the three years in the period ended December 31, 2025	F-9
Notes to consolidated financial statements	F-10

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company's financial statements and related notes.

3. Exhibits

EXHIBIT NO.	DESCRIPTION	Incorporated by Reference			
		Form	Exhibit	Filing Date	SEC File No.
3.1	Amended and Restated Certificate of Incorporation of Registrant, dated March 1, 2021.	8-K12B	3.1	3/1/2021	001-40144
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Registrant, dated May 24, 2023, as filed with the Secretary of State of the State of Delaware on May 24, 2023.	8-K	3.1	5/25/2023	001-40144
3.3	Amended and Restated Bylaws of Registrant, dated February 2, 2023.	8-K	3.1	2/8/2023	001-40144
4.1	Form of Certificate for Registrant's Common Stock.	8-K12B	4.1	3/1/2021	001-40144
4.2	Description of Equity Securities of Registrant.	8-K12B	4.2	3/1/2021	001-40144
4.3	Amended and Restated Warrant Agreement, dated April 1, 2024, by and among Registrant, Equiniti Trust Company, LLC, and, solely for purposes of certain provisions specified therein, Callon Petroleum Company.	8-K	4.1	4/1/2024	001-40144
4.4	Indenture, dated as of December 11, 2024, between Registrant and Regions Bank, as trustee.	POSASR	4.9	12/12/2024	333-279038
4.5	Indenture, dated as of June 30, 2021, between Registrant and Computershare Trust Company, N.A., as successor to Wells Fargo Bank, National Association, as trustee.	S-3ASR	4.4	6/30/2021	333-257556
10.1	Credit Agreement [USD Facility], dated as of January 15, 2025, among Registrant, the lenders party thereto, the issuing banks party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents party thereto.	8-K	10.1	1/16/2025	001-40144
10.2	Credit Agreement [GBP Facility], dated as of January 15, 2025, among Registrant, the lenders party thereto, the issuing banks party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents party thereto.	8-K	10.2	1/16/2025	001-40144
†10.3	Income Continuance Plan, as amended and restated effective as of March 1, 2021.	8-K12B	10.2	3/1/2021	001-40144
†10.4	Executive Termination Policy, as amended and restated effective as of March 1, 2021.	8-K12B	10.3	3/1/2021	001-40144
†10.5	2016 Omnibus Compensation Plan, dated February 3, 2016, effective May 12, 2016.	8-K	10.1	5/16/2016	001-04300
†10.6	Second Amendment to the 2016 Omnibus Compensation Plan, dated March 1, 2021.	8-K12B	10.6	3/1/2021	001-40144
†10.7	2011 Omnibus Equity Compensation Plan, as amended and restated May 12, 2016.	10-Q	10.1	8/4/2016	001-04300
†10.8	First Amendment to the 2011 Omnibus Equity Compensation Plan, dated July 29, 2019.	10-K	10.15	2/28/2020	001-04300
†10.9	Second Amendment to the 2011 Omnibus Equity Compensation Plan, dated March 1, 2021.	8-K12B	10.5	3/1/2021	001-40144
†10.10	Deferred Delivery Plan, as amended and restated May 12, 2016.	10-Q	10.3	8/4/2016	001-04300
†10.11	Non-Employee Directors' Compensation Plan, as amended and restated September 12, 2023.	10-Q	10.1	11/2/2023	001-40144
†10.12	Outside Directors' Retirement Plan, as amended and restated July 16, 2014, effective June 30, 2014.	10-Q	10.5	8/8/2014	001-04300
†10.13	Non-Employee Directors' Restricted Stock Units Program, effective May 12, 2016, pursuant to the 2016 Omnibus Compensation Plan.	10-Q	10.4	8/4/2016	001-04300
†10.14	Outside Directors' Deferral Program, effective May 12, 2016, pursuant to the 2016 Omnibus Compensation Plan.	10-Q	10.5	8/4/2016	001-04300
†10.15	Form of 2023 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 4, 2023.	8-K	10.1	1/6/2023	001-40144
†10.16	Form of Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan).	10-K	10.43	2/23/2023	001-40144
†10.17	Form of Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan).	10-K	10.44	2/23/2023	001-40144

EXHIBIT NO.	DESCRIPTION	Incorporated by Reference			
		Form	Exhibit	Filing Date	SEC File No.
†10.18	Form of 2024 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 8, 2024.	8-K	10.1	1/12/2024	001-40144
†10.19	Form of 2025 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 9, 2025.	8-K	10.1	1/10/2025	001-40144
†10.20	Form of Stock Option Award Agreement (2016 Omnibus Compensation Plan).	8-K	10.2	1/10/2025	001-40144
*†10.21	Form of 2026 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 6, 2026.				
*19.1	Insider Trading Policy.				
*21.1	Subsidiaries of Registrant.				
*23.1	Consent of Ernst & Young LLP.				
*23.2	Consent of Ryder Scott Company, L.P., Petroleum Consultants.				
*24.1	Power of Attorney (included as a part of the signature pages to this report).				
*31.1	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Executive Officer.				
*31.2	Certification (pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act) by Principal Financial Officer.				
**32.1	Section 1350 Certification (pursuant to Sarbanes-Oxley Section 906) by Principal Executive Officer and Principal Financial Officer.				
97.1	Executive Compensation Clawback Policy.	10-K	97.1	2/22/2024	001-40144
*99.1	Report of Ryder Scott Company, L.P., Petroleum Consultants.				
*101.INS	Inline XBRL Instance Document (the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document).				
*101.SCH	Inline XBRL Taxonomy Schema Document.				
*101.CAL	Inline XBRL Calculation Linkbase Document.				
*101.DEF	Inline XBRL Definition Linkbase Document.				
*101.LAB	Inline XBRL Label Linkbase Document.				
*101.PRE	Inline XBRL Presentation Linkbase Document.				
*104	Cover Page Interactive Data File (the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document).				

* Filed herewith.

** Furnished herewith.

† Management contracts or compensatory plans or arrangements required to be filed herewith pursuant to Item 15 hereof.

NOTE: Debt instruments of the Registrant defining the rights of long-term debt holders in principal amounts not exceeding 10 percent of the Registrant's consolidated assets have been omitted and will be provided to the Commission upon request.

ITEM 16. ***FORM 10-K SUMMARY***

None.

SIGNATURES

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

APA CORPORATION

/s/ John J. Christmann IV
John J. Christmann IV
Chief Executive Officer

Dated: February 26, 2026

POWER OF ATTORNEY

The officers and directors of APA Corporation, whose signatures appear below, hereby constitute and appoint John J. Christmann IV, Ben C. Rodgers, and Robert P. Rayphole, and each of them (with full power to each of them to act alone), the true and lawful attorney-in-fact to sign and execute, on behalf of the undersigned, any amendment(s) to this report and each of the undersigned does hereby ratify and confirm all that said attorneys shall do or cause to be done by virtue thereof.

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

Name	Title	Date
/s/ John J. Christmann IV John J. Christmann IV	Director and Chief Executive Officer (principal executive officer)	February 26, 2026
/s/ Ben C. Rodgers Ben C. Rodgers	Executive Vice President and Chief Financial Officer (principal financial officer)	February 26, 2026
/s/ Robert P. Rayphole Robert P. Rayphole	Vice President, Chief Accounting Officer, and Controller (principal accounting officer)	February 26, 2026
/s/ Annell R. Bay Annell R. Bay	Director	February 26, 2026
/s/ Matthew R. Bob Matthew R. Bob	Director	February 26, 2026
/s/ Juliet S. Ellis Juliet S. Ellis	Director	February 26, 2026
/s/ Kenneth M. Fisher Kenneth M. Fisher	Director	February 26, 2026
/s/ Charles W. Hooper Charles W. Hooper	Director	February 26, 2026
/s/ Chansoo Joung Chansoo Joung	Director	February 26, 2026
/s/ H. Lamar McKay H. Lamar McKay	Independent, Non-Executive Chair of the Board and Director	February 26, 2026
/s/ Peter A. Ragauss Peter A. Ragauss	Director	February 26, 2026
/s/ David L. Stover David L. Stover	Director	February 26, 2026
/s/ Anya Weaving Anya Weaving	Director	February 26, 2026

REPORT OF MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for the preparation and integrity of the consolidated financial statements appearing in this annual report on Form 10-K. The financial statements were prepared in conformity with accounting principles generally accepted in the United States and include amounts that are based on management's best estimates and judgments.

Management of the Company is responsible for establishing and maintaining effective internal control over financial reporting as such term is defined in Rule 13a-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by a program of internal audits and appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written code of business conduct adopted by our Company's board of directors, applicable to all Company directors and all officers and employees of our Company and subsidiaries.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework (2013)*. Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2025.

The Company's independent auditors, Ernst & Young LLP, a registered public accounting firm, are appointed by the Audit Committee of the Company's board of directors. Ernst & Young LLP have audited and reported on the consolidated financial statements of APA Corporation and subsidiaries and the effectiveness of the Company's internal control over financial reporting. The reports of the independent auditors follow this report on pages F-2 and F-3.

/s/ John J. Christmann IV
Chief Executive Officer
(principal executive officer)

/s/ Ben C. Rodgers
Executive Vice President and Chief Financial Officer
(principal financial officer)

/s/ Robert P. Rayphole
Vice President, Chief Accounting Officer and Controller
(principal accounting officer)

Houston, Texas
February 26, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of APA Corporation

Opinion on Internal Control Over Financial Reporting

We have audited APA Corporation and subsidiaries' internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, APA Corporation and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related statements of consolidated operations, comprehensive income, changes in equity and noncontrolling interest and cash flows for each of the three years in the period ended December 31, 2025, and the related notes and our report dated February 26, 2026 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of APA Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of APA Corporation and subsidiaries (the Company) as of December 31, 2025 and 2024, the related statements of consolidated operations, comprehensive income, changes in equity and noncontrolling interest and cash flows for each of the three years in the period ended December 31, 2025, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles.

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

Basis for Opinion

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

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

Critical Audit Matters

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

Depreciation, depletion and amortization of property and equipment

Description of the Matter	At December 31, 2025, the net carrying value of the Company's property and equipment was $12,748 million, and depreciation, depletion and amortization (DD&A) expense was $2,304 million for the year then ended. As described in Note 1, the Company follows the successful efforts method of accounting for its oil and gas properties. DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method based on proved oil and gas reserves, as estimated by the Company's internal reservoir engineers.

Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and natural gas liquids, 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. Judgment is required by the Company's internal reservoir engineers in estimating oil and gas reserves. Estimating proved oil and gas reserves requires the selection of inputs, including historical production, oil and gas price assumptions, and operating costs, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to audit the proved oil and gas reserve estimates prepared by the Company's internal reservoir engineers for select properties as of December 31, 2025.

Auditing the Company's DD&A calculations is complex because of the use of the work of the internal reservoir engineers and the independent petroleum engineers.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the data utilized by the engineers for use in estimating oil and gas reserves.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineers used to audit the proved oil and gas reserve estimates. Additionally, we evaluated the methods and assumptions used by the engineers in estimating proved oil and gas reserves and tested the completeness and accuracy of the data used by the engineers related to historical production volumes. We also tested that the DD&A expense calculations are based on the appropriate proved oil and gas reserve balances from the Company's reserve report.

Accounting for asset retirement obligation for the North Sea segment

Description of the Matter

At December 31, 2025, the asset retirement obligation (ARO) balance totaled $2,880 million. As further described in Note 7, the Company's ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties and other long-lived assets. The estimation of the ARO related to the North Sea segment requires significant judgment given the magnitude of the expected retirement costs.

Auditing the Company's ARO for the North Sea segment is complex and highly judgmental because of the significant estimation required by management in determining the obligation. In particular, the estimate was sensitive to retirement cost estimates, which are affected by expectations about future market and economic conditions.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligation.

To test the ARO for the North Sea segment, our audit procedures included, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost estimates. For example, we evaluated retirement cost estimates by comparing the Company's estimates to underlying third party evidence. We also involved our internal specialists in testing the underlying retirement cost estimates.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2002.

Houston, Texas
February 26, 2026

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2025	**2024**	**2023**
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil, natural gas, and natural gas liquids production revenues	$ 7,229	$ 8,196	$ 7,385
Purchased oil and gas sales	1,691	1,541	894
Total revenues	8,920	9,737	8,279
Derivative instrument gains (losses), net	(53)	(10)	99
Gain on divestitures, net	301	289	8
Gains (losses) on previously sold Gulf of America properties	60	(273)	(212)
Other, net	(8)	(6)	18
	9,220	9,737	8,192
OPERATING EXPENSES:			
Lease operating expenses	1,504	1,690	1,436
Gathering, processing, and transmission	424	432	334
Purchased oil and gas costs	1,070	1,047	742
Taxes other than income	229	270	207
Exploration	131	313	195
General and administrative	350	372	351
Transaction, reorganization, and separation	102	168	15
Depreciation, depletion, and amortization	2,304	2,266	1,540
Asset retirement obligation accretion	158	148	116
Impairments	44	1,129	61
Financing costs, net	113	367	312
	6,429	8,202	5,309
NET INCOME BEFORE INCOME TAXES	2,791	1,535	2,883
Current income tax provision	739	1,153	1,338
Deferred income tax provision (benefit)	360	(736)	(1,662)
NET INCOME INCLUDING NONCONTROLLING INTERESTS	1,692	1,118	3,207
Net income attributable to noncontrolling interest	258	314	352
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 1,434	$ 804	$ 2,855
NET INCOME PER COMMON SHARE:			
Basic	$ 3.99	$ 2.28	$ 9.26
Diluted	$ 3.99	$ 2.27	$ 9.25
WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	359	353	308
Diluted	359	353	309

The accompanying notes to consolidated financial statements are an integral part of this statement.

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
NET INCOME INCLUDING NONCONTROLLING INTERESTS	$ 1,692	$ 1,118	$ 3,207
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Pension and postretirement benefit plan	(2)	(3)	1
COMPREHENSIVE INCOME INCLUDING NONCONTROLLING INTERESTS	1,690	1,115	3,208
Comprehensive income attributable to noncontrolling interest	258	314	352
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON STOCK	$ 1,432	$ 801	$ 2,856

The accompanying notes to consolidated financial statements are an integral part of this statement.

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2025	**2024**	**2023**
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income including noncontrolling interests	$ 1,692	$ 1,118	$ 3,207
Adjustments to reconcile net income to net cash provided by operating activities:			
Unrealized derivative instrument (gains) losses, net	77	8	(51)
Gain on divestitures, net	(301)	(289)	(8)
Exploratory dry hole expense and unproved leasehold impairments	69	236	114
Depreciation, depletion, and amortization	2,304	2,266	1,540
Asset retirement obligation accretion	158	148	116
Impairments	44	1,129	61
Provision for (benefit from) deferred income taxes	360	(736)	(1,662)
Gain from extinguishment of debt	(147)	—	(9)
(Gains) losses on previously sold Gulf of America properties	(60)	273	212
Other	57	2	26
Changes in operating assets and liabilities:			
Receivables	850	(104)	(157)
Inventories	7	(11)	13
Drilling advances and other current assets	223	(56)	269
Deferred charges and other long-term assets	36	11	270
Accounts payable	(365)	81	(84)
Accrued expenses	(199)	(221)	(400)
Deferred credits and noncurrent liabilities	(260)	(235)	(328)
NET CASH PROVIDED BY OPERATING ACTIVITIES	4,545	3,620	3,129
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and gas property	(2,740)	(2,851)	(2,313)
Acquisition of Delaware Basin properties	—	—	(24)
Leasehold and property acquisitions	(26)	(60)	(20)
Proceeds from asset divestitures	611	1,609	29
Proceeds from sale of Kinetik shares	—	428	228
Other, net	2	(50)	(38)
NET CASH USED IN INVESTING ACTIVITIES	(2,153)	(924)	(2,138)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments on commercial paper and revolving credit facilities, net	(333)	(40)	(194)
Proceeds from term loan facility	—	1,500	—
Payments on term loan facility	(900)	(600)	—
Payment on Callon Credit Agreement	—	(472)	—
Fixed rate debt borrowings	846	—	—
Payments on fixed-rate debt	(1,016)	(1,641)	(65)
Distributions to noncontrolling interest	(430)	(268)	(238)
Dividends paid to APA common stockholders	(360)	(353)	(308)
Treasury stock activity, net	(280)	(246)	(329)
Other, net	(28)	(38)	(15)
NET CASH USED IN FINANCING ACTIVITIES	(2,501)	(2,158)	(1,149)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(109)	538	(158)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	625	87	245
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 516	$ 625	$ 87
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$ 281	$ 372	$ 329
Income taxes paid, net of refunds	999	1,097	1,271

The accompanying notes to consolidated financial statements are an integral part of this statement.

APA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31,	
	2025	2024
	(In millions, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 516	$ 625
Receivables, net of allowance of $140 and $123	1,062	1,959
Other current assets (Note 5)	543	820
	2,121	3,404
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of successful efforts accounting:	45,507	44,698
Gathering, processing, and transmission facilities	445	433
Other	536	562
Less: Accumulated depreciation, depletion, and amortization	(33,740)	(33,047)
	12,748	12,646
OTHER ASSETS:		
Decommissioning security for sold Gulf of America properties (Note 10)	21	21
Deferred tax asset (Note 9)	2,328	2,703
Deferred charges and other	543	616
	$ 17,761	$ 19,390
LIABILITIES, NONCONTROLLING INTEREST, AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 871	$ 1,224
Current debt	213	53
Other current liabilities (Note 6)	1,487	1,678
	2,571	2,955
LONG-TERM DEBT (Note 8)	4,280	5,991
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Deferred tax liability (Note 9)	—	14
Asset retirement obligation (Note 7)	2,699	2,591
Decommissioning contingency for sold Gulf of America properties (Note 10)	782	929
Other	426	548
	3,907	4,082
EQUITY:		
Common stock, $0.625 par, 860,000,000 shares authorized, 492,038,127 and 491,579,646 shares issued, respectively	308	307
Paid-in capital	12,816	13,153
Accumulated deficit	(721)	(2,155)
Treasury stock, at cost, 139,073,481 and 126,182,497 shares, respectively	(6,320)	(6,037)
Accumulated other comprehensive income	10	12
APA SHAREHOLDERS' EQUITY	6,093	5,280
Noncontrolling interest	910	1,082
TOTAL EQUITY	7,003	6,362
	$ 17,761	$ 19,390

The accompanying notes to consolidated financial statements are an integral part of this statement.

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CHANGES IN EQUITY AND NONCONTROLLING INTEREST

	Common Stock	Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Income	APA SHAREHOLDERS' EQUITY	Noncontrolling Interest	TOTAL EQUITY
					(In millions)			
BALANCE AT DECEMBER 31, 2022	$ 262	$ 11,420	$ (5,814)	$ (5,459)	$ 14	$ 423	$ 922	$ 1,345
Net income attributable to common stock	—	—	2,855	—	—	2,855	—	2,855
Net income attributable to noncontrolling interest	—	—	—	—	—	—	352	352
Distributions to noncontrolling interest	—	—	—	—	—	—	(238)	(238)
Common dividends ($1.00 per share)	—	(308)	—	—	—	(308)	—	(308)
Common stock activity, net	1	(14)	—	—	—	(13)	—	(13)
Treasury stock activity, net	—	—	—	(331)	—	(331)	—	(331)
Compensation expense	—	23	—	—	—	23	—	23
Other	—	5	—	—	1	6	—	6
BALANCE AT DECEMBER 31, 2023	$ 263	$ 11,126	$ (2,959)	$ (5,790)	$ 15	$ 2,655	$ 1,036	$ 3,691
Net income attributable to common stock	—	—	804	—	—	804	—	804
Net income attributable to noncontrolling interest	—	—	—	—	—	—	314	314
Distributions to noncontrolling interest	—	—	—	—	—	—	(268)	(268)
Common dividends ($1.00 per share)	—	(352)	—	—	—	(352)	—	(352)
Common stock activity, net	44	2,370	—	—	—	2,414	—	2,414
Treasury stock activity, net	—	—	—	(247)	—	(247)	—	(247)
Compensation expense	—	26	—	—	—	26	—	26
Other	—	(17)	—	—	(3)	(20)	—	(20)
BALANCE AT DECEMBER 31, 2024	$ 307	$ 13,153	$ (2,155)	$ (6,037)	$ 12	$ 5,280	$ 1,082	$ 6,362
Net income attributable to common stock	—	—	1,434	—	—	1,434	—	1,434
Net income attributable to noncontrolling interest	—	—	—	—	—	—	258	258
Distributions to noncontrolling interest	—	—	—	—	—	—	(430)	(430)
Common dividends ($1.00 per share)	—	(359)	—	—	—	(359)	—	(359)
Common stock activity, net	1	(6)	—	—	—	(5)	—	(5)
Treasury stock activity, net	—	—	—	(283)	—	(283)	—	(283)
Compensation expense	—	26	—	—	—	26	—	26
Other	—	2	—	—	(2)	—	—	—
BALANCE AT DECEMBER 31, 2025	$ 308	$ 12,816	$ (721)	$ (6,320)	$ 10	$ 6,093	$ 910	$ 7,003

The accompanying notes to consolidated financial statements are an integral part of this statement.

Nature of Operations

APA Corporation (APA or the Company) is an independent energy company that owns consolidated subsidiaries that explore for, develop, and produce crude oil, natural gas, and natural gas liquids. The Company's business has oil and gas operations in three geographic areas: the United States (U.S.), Egypt, and offshore the U.K. in the North Sea (North Sea). APA also has active development, exploration, and appraisal operations ongoing in Suriname, as well as exploration interests in Uruguay, Alaska, and other international locations that may, over time, result in reportable discoveries and development opportunities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by APA and its subsidiaries reflect industry practices and conform to accounting principles generally accepted in the U.S. (GAAP). The Company's financial statements for prior periods may include reclassifications that were made to conform to the current-year presentation. Significant accounting policies are discussed below.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of APA and its subsidiaries after elimination of intercompany balances and transactions.

The Company's undivided interests in oil and gas exploration and production ventures and partnerships are proportionately consolidated. The Company consolidates all other investments in which, either through direct or indirect ownership, it has more than a 50 percent voting interest or controls the financial and operating decisions.

Sinopec International Petroleum Exploration and Production Corporation (Sinopec) owns a one-third minority participation in the Company's consolidated Egypt oil and gas business as a noncontrolling interest, which is reflected as a separate noncontrolling interest component of equity in the Company's consolidated balance sheet. The Company has determined that a limited partnership and APA subsidiary, which has control over APA's Egyptian operations, qualifies as a variable interest entity (VIE) under GAAP. Apache consolidates the activities of APA's Egyptian operations because it has concluded that a wholly owned subsidiary has a controlling financial interest in APA's Egyptian operations and was determined to be the primary beneficiary of the VIE.

Use of Estimates

Preparation of financial statements in conformity with GAAP and disclosure of contingent assets and liabilities requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. The Company evaluates its estimates and assumptions on a regular basis. Actual results may differ from these estimates and assumptions used in preparation of the Company's financial statements, and changes in these estimates are recorded when known.

Significant estimates with regard to these financial statements include the estimates of fair value for long-lived assets (refer to "Fair Value Measurements" and "Property and Equipment" sections in this Note 1 below), the fair value determination of acquired assets and liabilities (refer to Note 2—Acquisitions and Divestitures), the assessment of asset retirement obligations (refer to Note 7—Asset Retirement Obligation), the estimate of income taxes (refer to Note 9—Income Taxes), the estimation of the contingent liability representing Apache's potential decommissioning obligations on sold properties in the Gulf of America (refer to Note 10—Commitments and Contingencies), and the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom (refer to Note 16—Supplemental Oil and Gas Disclosures (Unaudited)).

Fair Value Measurements

Certain assets and liabilities are reported at fair value on a recurring basis in the Company's consolidated balance sheet. Accounting Standards Codification (ASC) 820-10-35, "Fair Value Measurement" (ASC 820), provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models, and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

Refer to Note 4—Derivative Instruments and Hedging Activities, Note 8—Debt and Financing Costs, and Note 11—Retirement and Deferred Compensation Plans for further detail regarding the Company's fair value measurements recorded on a recurring basis.

The Company also uses fair value measurements on a nonrecurring basis when certain qualitative assessments of its assets indicate a potential impairment or when allocating the purchase price for acquired assets and liabilities in a business combination.

The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term nature and maturities of these instruments.

Impairments

The Company recorded $37 million and $11 million of asset impairments in connection with fair value assessments during the years ended December 31, 2025 and 2023, respectively.

During 2024, the Company performed an economic assessment of its North Sea assets in light of several new regulatory guidelines and obligations surrounding significant tax levies and modernization of aging infrastructure. The Company determined that expected returns did not economically support making investments required under the combined impact of the regulations and expects to cease production at its facilities in the North Sea prior to 2030. As a result, the Company performed a fair value assessment of the present value of its oil and gas assets in the North Sea as of the third quarter of 2024. Accordingly, the Company recognized impairments of $796 million on certain proved properties in the North Sea, which were written down to their estimated fair values as of the third quarter of 2024. This impairment is discussed in further detail below in "Property and Equipment — Oil and Gas Property."

Additionally, in the third quarter of 2024, the Company entered into an agreement to sell certain non-core U.S. oil and gas producing properties in the Permian Basin. As a result, a separate impairment analysis was performed for each of the assets within the disposal group. The analyses were based on the agreed-upon proceeds less costs to sell for the transaction, a Level 1 fair value measurement. The historical carrying value of the net assets to be divested exceeded the fair value implied by the expected net proceeds, resulting in an impairment totaling $315 million on the Company's proved properties in the U.S. Refer to Note 2—Acquisitions and Divestitures for more detail.

Allocation of Purchase Price

During 2024, APA completed its acquisition of Callon Petroleum Company (Callon) in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's debt (the Callon acquisition). The transaction was accounted for using the acquisition method of accounting, which requires, among other things, that assets acquired, and liabilities assumed be recognized at their fair values as of the acquisition date, using various Level 3 fair value measurements. Material assets and liabilities acquired are discussed further below:

- The most significant assumptions relate to the estimated fair values assigned to proved oil and natural gas properties. The fair value of proved oil and natural gas properties as of the acquisition date were estimated using the income approach, where fair value was determined based on the expected future cash flows from estimated proved oil, natural gas, and NGL reserves and related discounted future net cash flows as of that date. Significant inputs to the fair value estimate included estimates of future production volumes, future operating and development costs, future commodity prices, and a weighted-average cost of capital discount rate.
- The fair value of unproved properties was estimated mainly using the market approach, based on acreage costs in areas where Callon acreage was acquired.
- The fair value of most other current assets and current liabilities were determined to be equivalent to the carrying value due to their short-term nature.
- The fair value of debt was based on the estimated cost to retire Callon's debt instruments.
- Estimated deferred taxes were based on available information concerning the fair values assigned to acquired assets and liabilities and their respective tax basis and tax-related carryforwards at the acquisition date.

Refer to Note 2—Acquisitions and Divestitures for further detail regarding the Company's fair value measurements recorded related to the Callon acquisition.

Revenue Recognition

The Company's oil and gas segments primarily generate revenue from contracts with customers from the sale of its crude oil, natural gas, and natural gas liquids production volumes. In addition to APA-related production volumes, the Company also sells commodity volumes purchased from third parties to provide flexibility to fulfill sales obligations and commitments. Under these commodity sales contracts, the physical delivery of each unit of quantity represents a single, distinct performance obligation on behalf of the Company. Contract prices are determined based on market-indexed prices, adjusted for quality, transportation, and other market-reflective differentials. Revenue is measured by allocating an entirely variable market price to each performance obligation and recognized at a point in time when control is transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to: whether the purchaser can direct the use of the hydrocarbons, the transfer of significant risks and rewards, and the Company's right to payment. Control typically transfers to customers upon the physical delivery at specified locations within each contract and the transfer of title.

APA's Egypt operations are conducted pursuant to production-sharing contracts (PSCs). Under the terms of the Company's PSCs, the Company is the contractor partner (Contractor) with the Egyptian General Petroleum Corporation (EGPC) and bears the risk and cost of exploration, development, and production activities. In return, if exploration is successful, the Contractor receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of production after cost recovery. Additionally, the Contractor's income taxes, which remain the liability of the Contractor under domestic law, are paid by EGPC on behalf of the Contractor out of EGPC's production entitlement. Income taxes paid to the Arab Republic of Egypt on behalf of the Contractor are recognized as oil and gas sales revenue and income tax expense and reflected as production and estimated reserves. Because Contractor cost recovery entitlement and income taxes paid on its behalf are determined as a monetary amount, the quantities of production entitlement and estimated reserves attributable to these monetary amounts will fluctuate with commodity prices. In addition, because the Contractor income taxes are paid by EGPC, the amount of the income tax has no economic impact on the Company's Egypt operations despite impacting the Company's production and reserves.

Refer to Note 16—Business Segment Information for a disaggregation of revenue by product and reporting segment.

Payment Terms and Contract Balances

Receivables from contracts with customers, including receivables for purchased oil and gas sales and net of allowance for credit losses, were $826 million and $1.7 billion as of December 31, 2025 and 2024, respectively. Payments under all contracts with customers are typically due and received within a short-term period of one year or less, after physical delivery of the product or service has been rendered. During 2025, the Company observed a meaningful improvement in the timing of payments from the Egyptian General Petroleum Corporation (EGPC). As a result of more consistent remittances during the year, the Company's outstanding receivable balance from this customer was current as of December 31, 2025. This improvement follows several periods prior to 2025 during which EGPC payments were delayed and the receivable balance increased. While recent collections have been timely, the Company continues to closely monitor its exposure to EGPC, as payment patterns may vary over time.

In accordance with the provisions of ASC 606, "Revenue from Contracts with Customers," variable market prices for each short-term commodity sale are allocated entirely to each performance obligation as the terms of payment relate specifically to the Company's efforts to satisfy its obligations. As such, the Company has elected the practical expedients available under the standard to not disclose the aggregate transaction price allocated to unsatisfied, or partially unsatisfied, performance obligations as of the end of the reporting period.

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with a maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value. As of December 31, 2025 and 2024, the Company had $516 million and $625 million, respectively, of cash and cash equivalents. The Company had no restricted cash as of December 31, 2025 and 2024.

Accounts Receivable and Allowance for Credit Losses

Accounts receivable are stated at amortized cost net of an allowance for credit losses. The Company routinely assesses the collectability of its financial assets measured at amortized cost. The Company monitors the credit quality of its counterparties through review of collections, credit ratings, and other analyses. The Company develops its estimated allowance for expected credit losses primarily using an aging method and analyses of historical loss rates as well as consideration of current and future conditions that could impact its counterparties' credit quality and liquidity.

The following table presents changes to the Company's allowance for credit loss:

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Allowance for credit loss at beginning of year	$ 123	$ 114	$ 117
Additional provisions for the year	20	9	16
Uncollectible accounts written off, net of recoveries	(3)	—	(19)
Allowance for credit loss at end of year	$ 140	$ 123	$ 114

Inventories

Inventories consist principally of tubular goods and equipment and are stated at the lower of weighted-average cost or net realizable value. Oil produced but not sold, primarily in the North Sea, is also recorded to inventory and is stated at the lower of the cost to produce or net realizable value.

During 2025, the Company recorded $7 million of inventory impairments in the North Sea. During 2024, the Company recorded $18 million of inventory impairments, including $13 million in the North Sea and $5 million in the U.S. During 2023, the Company recorded impairments of approximately $50 million in connection with valuations of drilling and operations equipment inventory upon the Company's decision to suspend drilling operations in the North Sea.

Property and Equipment

The carrying value of the Company's property and equipment represents the cost incurred to acquire the property and equipment, including capitalized interest, net of any impairments. For business combinations and acquisitions, property and equipment cost is based on the fair values at the acquisition date.

Oil and Gas Property

The Company follows the successful efforts method of accounting for its oil and gas property. Under this method of accounting, exploration costs, such as exploratory geological and geophysical costs, delay rentals, and exploration overhead, are expensed as incurred. All costs related to production, general corporate overhead, and similar activities are expensed as incurred. If an exploratory well provides evidence to justify potential development of reserves, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations. At the end of each quarter, management reviews the status of all suspended exploratory well costs in light of ongoing exploration activities; in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are assessed for impairment at least annually and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment based on the Company's current exploration plans. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis over the average lease term at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged to exploration expense, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration costs in the statement of consolidated operations.

The following table represents non-cash impairment charges of the carrying value of the Company's proved and unproved properties:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Proved properties:			
U.S.	$ —	$ 315	$ —
Egypt	18	—	—
North Sea	—	796	—
Total proved properties	$ 18	$ 1,111	$ —
Unproved properties:			
U.S.	$ —	$ 34	$ 10
Egypt	2	—	—
North Sea	—	—	11
Other International	—	1	1
Total unproved properties	$ 2	$ 35	$ 22

Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized. Depreciation of the cost of proved oil and gas properties is calculated using the unit-of-production (UOP) method. The UOP calculation multiplies the percentage of estimated proved reserves produced each quarter by the carrying value of associated proved oil and gas properties. The reserve base used to calculate depreciation for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate the depreciation for capitalized well costs is the sum of proved developed reserves only. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are included in the depreciable cost.

Oil and gas properties are grouped for depreciation in accordance with ASC 932, "Extractive Activities—Oil and Gas." The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

When circumstances indicate that the carrying value of proved oil and gas properties may not be recoverable, the Company compares unamortized capitalized costs to the expected undiscounted pre-tax future cash flows for the associated assets grouped at the lowest level for which identifiable cash flows are independent of cash flows of other assets. If the expected undiscounted pre-tax future cash flows, based on the Company's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally estimated using the income approach described in ASC 820. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments, a Level 3 fair value measurement. During the year ended December 31, 2025, the Company recorded $18 million of impairments to its proved properties in Egypt.

During 2024, the Company updated its cessation-of-production dates for its North Sea operations, as discussed above in "Fair Value Measurements." This change significantly altered the Company's remaining oil and gas reserves in the North Sea and triggered an impairment assessment of the Company's proved oil and gas properties at the end of the third quarter of 2024. Future production volumes and estimated future commodity prices are the largest drivers in the variability of future cash flows. Expected cash flows were estimated based on management's views of forward pricing as of the balance sheet dates. A discount rate based on a market-based weighted-average cost of capital estimate was applied to the undiscounted cash flow estimate to value the Company's North Sea assets. In connection with this assessment, the Company recorded impairments totaling $796 million on certain of the Company's North Sea proved properties to an aggregate fair value of $263 million.

Additionally, in the third quarter of 2024, the Company entered into an agreement to sell certain non-core U.S. oil and gas producing properties in the Permian Basin. As a result, a separate impairment analysis was performed for each of the assets within the disposal group. The analyses were based on the agreed-upon proceeds less costs to sell for the transaction, a Level 1 fair value measurement. The historical carrying value of the net assets to be divested exceeded the fair value implied by the expected net proceeds, resulting in an impairment totaling $315 million on the Company's proved properties in the U.S. Refer to Note 2—Acquisitions and Divestitures for more detail.

For the year ended December 31, 2023, the Company recorded no impairments of proved properties.

Gains and losses on divestitures of the Company's oil and gas properties are recognized in the statement of consolidated operations upon closing of the transaction. Refer to Note 2—Acquisitions and Divestitures for more detail.

Gathering, Processing, and Transmission (GPT) Facilities

GPT facilities totaled $445 million and $433 million at December 31, 2025 and 2024, respectively, with accumulated depreciation for these assets totaling $383 million and $364 million for the respective periods. GPT facilities are depreciated on a straight-line basis over the estimated useful lives of the assets. The estimation of useful life takes into consideration anticipated production lives from the fields serviced by the GPT assets, whether APA-operated or third party-operated, as well as potential development plans by the Company for undeveloped acreage within, or close to, those fields.

For the year ended December 31, 2025, the Company recorded $1 million in impairments of GPT facilities in Egypt. For each of the years ended December 31, 2024 and 2023, the Company recorded no impairments of GPT facilities.

Other Property and Equipment

Other property and equipment includes computer software and equipment, buildings, vehicles, furniture and fixtures, land, and other equipment. These assets are depreciated on a straight-line basis over the estimated useful lives of the assets, which range from 3 to 20 years. Other property and equipment, net of accumulated depreciation totaled $146 million and $183 million at December 31, 2025 and 2024, respectively.

For the year ended December 31, 2025, the Company recorded an $18 million impairment for the anticipated sale of an office building.

Asset Retirement Costs and Obligations

The initial estimated asset retirement obligation related to property and equipment and subsequent revisions are recorded as a liability at fair value, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of an asset's retirement. Asset retirement costs are depreciated using a systematic and rational method similar to that used for the associated property and equipment. Accretion expense on the liability is recognized over the estimated productive life of the related assets.

Capitalized Interest

For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties actively being explored and significant exploration and development projects that have not commenced production that are undergoing the construction of assets that have not commenced principal operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation.

Commitments and Contingencies

Accruals for loss contingencies arising from claims, assessments, litigation, environmental, and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change. For more information regarding loss contingencies, refer to Note 10—Commitments and Contingencies.

Derivative Instruments and Hedging Activities

The Company periodically enters into derivative contracts to manage its exposure to commodity price, interest rate, and/or foreign exchange risk. These derivative contracts, which are generally placed with major financial institutions, may take the form of forward contracts, futures contracts, swaps, or options.

All derivative instruments, other than those that meet the normal purchases and sales exception, are recorded on the Company's consolidated balance sheet as either an asset or liability measured at fair value. The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses from the change in fair value of derivative instruments are reported in current-period income as "Derivative instrument gains (losses), net" under "Revenues and Other" in the statement of consolidated operations. Refer to Note 4—Derivative Instruments and Hedging Activities for further information.

Income Taxes

The Company records deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. The Company routinely assesses the ability to realize its deferred tax assets. If the Company concludes that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. Refer to Note 9—Income Taxes for further information.

In December 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2023-09, Improvements to Income Tax Disclosures (ASU 2023-09). ASU 2023-09 is intended to improve income tax disclosures primarily through enhanced disclosure of income tax rate reconciliation items, and disaggregation of income from continuing operations, income tax (expense) benefit, and income taxes paid, net disclosures by federal, state and foreign jurisdictions, among other items. This ASU is effective for annual reporting periods beginning after December 15, 2024. ASU 2023-09 should be applied on a prospective basis, although retrospective application is permitted. The Company adopted ASU 2023-09 retrospectively for the year ended December 31, 2025, and it did not have a material impact on the Company's financial statements.

Earnings Per Share

The Company's basic earnings per share (EPS) amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS reflects potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock was fully vested.

Stock-Based Compensation

The Company grants various types of stock-based awards including stock options, restricted stock, cash-settled restricted stock units, and performance-based awards. Stock compensation equity awards granted are valued on the date of grant and are expensed over the required vesting service period. Cash-settled awards are recorded as a liability based on the Company's stock price and remeasured at the end of each reporting period over the vesting terms. The Company has elected to account for forfeitures as they occur rather than estimate expected forfeitures. The Company's stock-based compensation plans and related accounting policies are defined and described more fully in Note 12—Capital Stock.

Treasury Stock

The Company follows the weighted-average-cost method of accounting for treasury stock transactions.

Transaction, Reorganization, and Separation (TRS)

The Company recorded TRS costs in 2025 totaling $102 million, which comprised primarily employee separations in the U.S. and organization restructuring in the North Sea.

The Company recorded TRS costs in 2024 totaling $168 million, which primarily comprised $147 million associated with the Callon acquisition, including $76 million of separation costs and $71 million of transaction and integration costs.

The Company recorded TRS costs in 2023 totaling $15 million including $7 million related to consulting and separation costs in international operations.

New Pronouncements Issued But Not Yet Adopted

In November 2024, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2024-03, "Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40)," which expands disclosures around a public entity's costs and expenses of specific items (i.e. employee compensation, DD&A), requires the inclusion of amounts that are required to be disclosed under GAAP in the same disclosure as other disaggregation requirements, requires qualitative descriptions of amounts remaining in expense captions that are not separately disaggregated quantitatively, and requires disclosure of total selling expenses, and in annual periods, the definition of selling expenses. The amendment does not change or remove existing disclosure requirements. The amendment is effective for fiscal years beginning after December 15, 2026, and interim periods with fiscal years beginning after December 15, 2027. Early adoption is permitted, and the amendment can be adopted prospectively or retrospectively to any or all periods presented in the financial statements. The Company is currently assessing the impact of adopting this standard.

2. ACQUISITIONS AND DIVESTITURES

2025 Activity

Leasehold and Property Acquisitions

During 2025, the Company completed leasehold acquisitions, primarily in the Permian Basin, for aggregate cash consideration of approximately $26 million.

During the third quarter of 2025, the Government of Egypt awarded the Company an additional two million net exploration acres in the Western Desert. In addition to a signature bonus of $25 million, the Company has committed to a drilling program on the acreage that the Company believes it will be able to meet in the normal course of operations.

U.S. Divestitures

During the second quarter of 2025, the Company completed the sale of all of its New Mexico Permian assets. The assets had a carrying value of $282 million and associated retirement obligation of $9 million, which were exchanged for total cash consideration of $571 million, inclusive of post-closing adjustments. The Company recognized a gain of $299 million in association with this sale. Proceeds from the transaction were used primarily for debt reduction.

2024 Activity

Callon Petroleum Company Acquisition

On April 1, 2024, APA completed its acquisition of Callon in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's debt. Subject to the terms of the merger agreement, each share of Callon common stock was converted into the right to receive 1.0425 shares of APA common stock, with cash in lieu of fractional shares. As a result, APA issued approximately 70 million shares of APA common stock in connection with the transaction, and following the acquisition, Callon common stock is no longer listed for trading on the NYSE.

Recording of Assets Acquired and Liabilities Assumed

The transaction was accounted for using the acquisition method of accounting, which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The table below presents the finalized value of the assets acquired and liabilities assumed.

		(In millions)
Current assets	$	287
Property and equipment		4,502
Deferred tax asset		565
Other assets		12
Total assets acquired	$	5,366
Current liabilities	$	632
Long-term debt		2,113
Asset retirement obligation		136
Other long-term obligations		48
Total liabilities assumed	$	2,929
Net assets acquired	$	2,437

The following unaudited pro forma combined results for the years ended December 31, 2024 and 2023 reflect the consolidated results of operations of the Company as if the Callon acquisition had occurred on January 1, 2023. The unaudited pro forma information includes certain accounting adjustments for transaction costs, depreciation, depletion, and amortization expense, and estimated tax impacts of the pro forma adjustments.

	For the Year Ended December 31,	
	2024	2023
	(In millions)	
Revenues	$ 10,300	$ 10,578
Net income attributable to common stock	909	4,021
Net income per common share – basic	2.45	10.66
Net income per common share – diluted	2.45	10.63

From the date of the acquisition through December 31, 2024, revenues and net income attributable to common stockholders associated with Callon assets totaled $1.2 billion and $262 million, respectively.

The unaudited pro forma condensed consolidated financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated. The unaudited pro forma results are also not intended to be a projection of future results and do not include any future cost savings or other synergies that may result from the Callon acquisition or any estimated costs that have not yet been incurred.

Leasehold and Property Acquisitions

During 2024, in addition to the Callon acquisition, the Company completed other leasehold and property acquisitions, primarily in the Permian Basin, for aggregate cash consideration of approximately $60 million.

U.S. Divestitures

During 2024, the Company completed the sale of non-core acreage in the East Texas Austin Chalk and Eagle Ford plays that had a carrying value of $347 million for aggregate cash proceeds of $255 million and the assumption of asset retirement obligations of $42 million. The Company recognized a $50 million loss during 2024 in association with this sale.

During 2024, the Company also completed the sale of non-core mineral and royalty interests in the Permian Basin that had a carrying value of $71 million for approximately $394 million subject to post-closing adjustments. The Company recognized a gain of $321 million in association with this sale.

Additionally, the Company completed the sale of non-core assets and leasehold in multiple transactions for aggregate cash proceeds of $91 million, recognizing a gain of approximately $22 million upon closing of these transactions.

On December 31, 2024, APA completed the sale of non-core producing properties in the Permian Basin that had a carrying value of $1.1 billion and associated asset retirement obligation of $224 million for total cash proceeds of $869 million after closing adjustments. The properties are located in the Central Basin Platform, Texas and New Mexico Shelf, and Northwest Shelf. The effective date of the transaction was July 1, 2024. As a result of the transaction, the Company performed a fair value assessment of the associated assets and liabilities and recorded an impairment of $315 million to the carrying value of the associated oil and gas properties during the third quarter of 2024. During the fourth quarter of 2024, the Company recorded a loss of $5 million upon closing of the transaction.

Sale of Kinetik Shares

On March 18, 2024, the Company sold its remaining shares of Kinetik Holdings Inc. (Kinetik) Class A Common Stock (Kinetik Shares) for cash proceeds of $428 million.

The following table represents related party sales and costs associated with Kinetik, when the Company was considered to have had significant influence over Kinetik prior to the Company's sale of its remaining Kinetik Shares and the resignation of the Company's designated director from the Kinetik board of directors:

	For the Year Ended December 31,	
	2024	2023
	(In millions)	
Natural gas and NGLs sales	$ 13	$ 92
Purchased oil and gas sales	22	29
	$ 35	$ 121
Gathering, processing, and transmission costs	$ 23	$ 108
Purchased oil and gas costs	23	80
Lease operating expenses	2	7
	$ 48	$ 195

2023 Activity

Sale of Kinetik Shares

In December 2023, the Company sold 7.5 million of its Kinetik Shares for cash proceeds of $228 million.

Leasehold and Property Acquisitions

During 2023, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of approximately $20 million.

U.S. Divestitures

During 2023, the Company completed the sale of non-core assets and leasehold in multiple transactions for total cash proceeds of $29 million, recognizing an aggregate gain of approximately $8 million upon closing of these transactions.

3. CAPITALIZED EXPLORATORY WELL COSTS

The following summarizes the changes in capitalized exploratory well costs for the years ended December 31, 2025, 2024, and 2023. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Capitalized well costs at beginning of year	$ 237	$ 586	$ 474
Additions pending determination of proved reserves	234	240	265
Reclassifications to proved properties	(118)	(506)	(135)
Charged to exploration expense	(15)	(83)	(18)
Capitalized well costs at end of year	$ 338	$ 237	$ 586

The following provides an aging of capitalized exploratory well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling as of December 31:

	2025	2024	2023
		(In millions)	
Exploratory well costs capitalized for a period of one year or less	$ 158	$ 107	$ 156
Exploratory well costs capitalized for a period greater than one year	180	130	430
Capitalized well costs at end of year	$ 338	$ 237	$ 586
Number of projects with exploratory well costs capitalized for a period greater than one year	7	12	33

Projects with exploratory well costs capitalized for a period greater than one year since the completion of drilling are those identified by management as exhibiting sufficient quantities of hydrocarbons to justify potential development. Management is actively pursuing efforts to assess whether reserves can be attributed to these projects. Exploratory well costs capitalized for a period greater than one year since completion of drilling were $180 million at December 31, 2025, with $121 million related to Suriname exploration and appraisal. Analysis of well results and appraisal activity is ongoing. The remaining projects pertain to onshore drilling activity in Egypt and Alaska, for which continued testing and evaluation is being performed.

Dry hole expenses from suspended exploratory well costs previously capitalized for greater than one year at December 31, 2024 totaled $8 million. These expenses pertained to projects in Egypt.

The following table summarizes aging by geographic area of those exploratory well costs that, as of December 31, 2025, have been capitalized for a period greater than one year, categorized by the year in which drilling was completed:

	Total	2024	2023	2022 and Prior
		(In millions)		
Suriname	$ 121	$ —	$ 60	$ 61
United States	48	48	—	—
Egypt	11	7	4	—
	$ 180	$ 55	$ 64	$ 61

4. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Objectives and Strategies

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its worldwide production, as well as fluctuations in exchange rates in connection with transactions denominated in foreign currencies. The Company manages the variability in its cash flows by occasionally entering into derivative transactions on a portion of its crude oil and natural gas production and foreign currency transactions. The Company utilizes various types of derivative financial instruments, including forward contracts, futures contracts, swaps, and options, to manage fluctuations in cash flows resulting from changes in commodity prices or foreign currency values. The Company elected not to designate any of its derivative contracts as cash flow hedges.

Counterparty Risk

The use of derivative instruments exposes the Company to credit loss in the event of nonperformance by the counterparty. To reduce the concentration of exposure to any individual counterparty, the Company utilizes a diversified group of investment-grade rated counterparties, primarily financial institutions, for its derivative transactions. As of December 31, 2025, the Company had derivative positions with 10 counterparties. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments resulting from lower commodity prices.

Derivative Instruments

Commodity Derivative Instruments

As of December 31, 2025, the Company had the following open natural gas financial basis swap contracts:

		Basis Swap Purchased		Basis Swap Sold	
Production Period	Settlement Index	MMBtu (in 000's)	Weighted Average Price Differential	MMBtu (in 000's)	Weighted Average Price Differential
January—December 2026	NYMEX Henry Hub/IF Waha	89,425	$(1.96)	—	—

Foreign Currency Derivative Instruments

Subsequent to December 31, 2025, the Company entered into foreign currency costless collar contracts in GBP/USD for £12 million per each calendar month for March through December 2026, with a weighted average floor and ceiling price of $1.32 and $1.40, respectively.

Fair Value Measurements

The following table presents the Company's derivative assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements Using					
	Quoted Price in Active Markets (Level 1)	Significant Other Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Netting[1]	Carrying Amount
			(In millions)			
December 31, 2025						
Liabilities:						
Commodity derivative instruments	$ —	$ 77	$ —	$ 77	$ —	$ 77
December 31, 2024						
Liabilities:						
Contingent consideration arrangements	$ —	$ 18	$ —	$ 18	$ —	$ 18

(1) The derivative fair values are based on analysis of each contract on a gross basis, excluding the impact of netting agreements with counterparties.

The fair values of the Company's commodity derivative instruments are not actively quoted in the open market. The Company primarily uses a market approach to estimate the fair values of these derivatives on a recurring basis, utilizing futures pricing for the underlying positions provided by a reputable third party, a Level 2 fair value measurement.

Derivative Activity Recorded in the Consolidated Balance Sheet

All derivative instruments are reflected as either assets or liabilities at fair value in the consolidated balance sheet. These fair values are recorded by netting asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. The carrying value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	For the Year Ended December 31,	
	2025	2024
	(In millions)	
Current Liabilities: Other current liabilities	$ 77	$ —
Deferred Credits and Other Noncurrent Liabilities: Other	$ —	$ 18
Total derivative liabilities	$ 77	$ 18

Derivative Activity Recorded in the Statement of Consolidated Operations

The following table summarizes the effect of derivative instruments on the Company's statement of consolidated operations:

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Realized:			
Commodity derivative instruments	$ 31	$ 2	$ 48
Contingent consideration arrangements	(7)	(4)	—
Realized gains (losses), net	24	(2)	48
Unrealized:			
Commodity derivative instruments	(77)	(6)	51
Contingent consideration arrangements	—	(2)	—
Unrealized gains (losses), net	(77)	(8)	51
Derivative instrument gains (losses), net	$ (53)	$ (10)	$ 99

Derivative instrument gains and losses are recorded in "Derivative instrument gains (losses), net" under "Revenues and Other" in the Company's statement of consolidated operations. Unrealized gains (losses) for derivative activity recorded in the statement of consolidated operations are reflected in the statement of consolidated cash flows separately as "Unrealized derivative instrument (gains) losses, net" under "Adjustments to reconcile net income to net cash provided by operating activities."

5. OTHER CURRENT ASSETS

The following table provides detail of the Company's other current assets as of December 31:

	2025	2024
	(In millions)	
Inventories	$ 351	$ 425
Drilling advances	93	184
Current decommissioning security for sold Gulf of America assets	19	157
Prepaid assets and other	80	54
Total Other current assets	$ 543	$ 820

6. OTHER CURRENT LIABILITIES

The following table provides detail of the Company's other current liabilities as of December 31:

	2025	2024
	(In millions)	
Accrued operating expenses	$ 129	$ 204
Accrued exploration and development	289	460
Accrued compensation and benefits	265	223
Accrued interest	88	93
Accrued income taxes	112	221
Current asset retirement obligation	181	103
Current operating lease liability	97	118
Current decommissioning contingency for sold Gulf of America properties	99	88
Other	227	168
Total Other current liabilities	$ 1,487	$ 1,678

7. ASSET RETIREMENT OBLIGATION

The following table describes changes to the Company's asset retirement obligation (ARO) liability for the years ended December 31, 2025 and 2024:

	For the Year Ended December 31,	
	2025	2024
	(In millions)	
Asset retirement obligation at beginning of the year	$ 2,694	$ 2,438
Liabilities incurred	23	15
Liabilities acquired	—	136
Liabilities divested	(8)	(272)
Liabilities settled	(100)	(70)
Accretion expense	158	148
Revisions in estimated liabilities	113	299
Asset retirement obligation at end of the year	2,880	2,694
Less current portion	(181)	(103)
Asset retirement obligation, long-term	$ 2,699	$ 2,591

The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties and other long-lived assets. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property or other long-lived asset balance.

During 2025 and 2024, the Company recorded $23 million and $15 million, respectively, in abandonment liabilities resulting from the Company's exploration and development capital program. Liabilities settled primarily relate to individual properties, platforms, and facilities plugged and abandoned during the period. During 2025 and 2024, net abandonment costs were revised upward by approximately $113 million and $299 million, respectively, primarily reflecting changes in estimates of timing and activity costs in the U.S. and North Sea, in addition to foreign currency exchange rates on service costs.

8. DEBT AND FINANCING COSTS

Overview

The debt of APA and Apache is senior unsecured debt and has equal priority with respect to the payment of both principal and interest.

The Company records gains and losses on extinguishment of debt in "Financing costs, net" in the Company's statement of consolidated operations.

The following table presents the carrying value of the Company's debt as of December 31, 2025 and 2024:

	December 31,	
	2025	2024
	(In millions)	
4.625% notes due 2025	$ —	$ 51
7.70% notes due 2026[1][3]	79	78
7.95% notes due 2026[1][3]	132	132
4.875% notes due 2027[1][2]	108	108
4.375% notes due 2028[1][2]	315	325
7.75% notes due 2029[1][3][4]	232	235
4.250% notes due 2030[1][2]	475	516
6.10% notes due 2035[2]	350	—
6.000% notes due 2037[1][2]	433	443
5.100% notes due 2040[1][2]	763	1,333
5.250% notes due 2042[1][2]	244	399
4.750% notes due 2043[1][2]	217	428
4.250% notes due 2044[1][2]	100	211
7.375% debentures due 2047[1][3]	150	150
5.350% notes due 2049[1][2]	374	387
6.75% notes due 2055[2]	500	—
7.625% debentures due 2096[1][3]	39	39
Notes and debentures before unamortized discount and debt issuance costs[5][6]	4,511	4,835
Commercial paper	—	323
Term loan facility	—	900
Syndicated credit facilities[7]	—	10
Apache finance lease obligations	28	30
Unamortized discount	(23)	(25)
Debt issuance costs	(23)	(29)
Total debt	4,493	6,044
Current maturities	(213)	(53)
Long-term debt	$ 4,280	$ 5,991

(1) This series of indenture debt includes series separately issued by APA and by Apache (see "APA Exchange and Tender Offers for Apache Indenture Debt" in this Note 8 below). The indicated amount as of December 31, 2025 is an aggregate amount for APA and Apache debt of this series. The indicated amount as of December 31, 2024 is solely Apache debt of this series; there was no APA indenture debt outstanding on December 31, 2024.
(2) These notes are redeemable, in whole or in part, at the issuer's option, subject to a make-whole premium.
(3) These notes and debentures are not redeemable, except that the 7.75% notes due 2029 for which Apache is obligated are redeemable in whole for principal and accrued interest in the event of certain Canadian tax law changes.
(4) Outstanding 7.75% notes due 2029 for which Apache is obligated were assumed by Apache in August 2017 as permitted by terms of such notes originally issued by a subsidiary and guaranteed by Apache.
(5) The aggregate amount as of December 31, 2025 is comprised of $3.6 billion for APA notes and debentures and $932 million for Apache notes and debentures. The aggregate amount as of December 31, 2024 is comprised solely of Apache indenture debt; there was no APA indenture debt on December 31, 2024.
(6) The fair values of the notes and debentures were $4.3 billion and $4.4 billion as of December 31, 2025 and 2024, respectively. The Company uses a market approach to determine the fair value of its notes and debentures using estimates provided by an independent investment financial data services firm (a Level 2 fair value measurement).
(7) The carrying amount of borrowings on credit facilities approximates fair value because the interest rates are variable and reflective of market rates.

Maturities for the Company's notes and debentures excluding discount and debt issuance costs as of December 31, 2025 are as follows:

	(In millions)
2026	$ 211
2027	108
2028	315
2029	232
2030	475
Thereafter	3,170
Notes and debentures, excluding discounts and debt issuance costs	$ 4,511

Financing Costs, Net

The following table presents the components of the Company's financing costs, net:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Interest expense	$ 323	$ 402	$ 351
Amortization of debt issuance costs	7	6	4
Capitalized interest	(45)	(29)	(24)
Gain on extinguishment of debt	(147)	—	(9)
Interest income	(25)	(12)	(10)
Financing costs, net	$ 113	$ 367	$ 312

Indenture Debt Activity

On August 20, 2025, Apache redeemed the outstanding $51 million principal amount of 4.625% Notes due 2025, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date.

During 2025, the Company purchased in the open market and had canceled indebtedness issued under indentures of APA and Apache in an aggregate principal amount of $122 million for an aggregate purchase price of $112 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $13 million. The Company recognized a $12 million gain on these repurchases. The repurchases were partially financed by APA's borrowing under the Company's commercial paper program. Refer to discussion of APA exchange and tender offers for Apache indenture debt below for further details regarding the gain on extinguishment of debt during the quarter ended March 31, 2025.

During 2023, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $74 million for an aggregate purchase price of $65 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $10 million. The Company recognized a $9 million gain on these repurchases. The repurchases were partially financed by Apache's borrowing under the Company's US dollar-denominated revolving credit facility.

The indentures under which APA has issued senior notes and debentures restrict it from issuing or guaranteeing certain secured indebtedness, consolidating with or merging into another person, and transferring or leasing its properties and assets as an entirety or substantially as an entirety to any person. Indentures of APA and Apache do not contain prepayment obligations in the event of a decline in credit ratings. In connection with the transactions summarized below under "APA Exchange and Tender Offers for Apache Indenture Debt", Apache's indentures were amended on January 10, 2025 to remove certain restrictive and reporting covenants, except those applicable to certain notes maturing in 2026 and 2027.

APA Exchange and Tender Offers for Apache Indenture Debt

On January 10, 2025, the Company settled its private exchange and cash tender offers for certain notes and debentures issued by Apache under its indentures. The Company also then settled its private offering of new notes to fund in part its purchase of Apache notes in APA's cash tender offers. In settling these offerings pursuant to their respective terms:

- APA issued new notes and debentures under its indentures in aggregate principal amounts of (i) $2.5 billion in exchange for Apache notes and debentures tendered and accepted in APA's exchange offers, (ii) $203 million in exchange for Apache notes tendered in the cash tender offers in excess of the stated maximum purchase amount or series caps, and (iii) $850 million in the new notes offering, comprised of $350 million aggregate principal amount of APA's 6.10% Notes due 2035 and $500 million aggregate principal amount of APA's 6.75% Notes due 2055.
- In addition to issuing the APA notes in the exchange offers, APA paid a total of $2.5 million in cash as part of the exchange consideration.
- APA paid a total of $869 million in cash in the tender offers (comprised of tender offer consideration, exchange consideration for tendered notes exchanged, early participation premium, and accrued interest) for the aggregate $1 billion in principal amount of Apache notes tendered and accepted in the cash tender offers. The Company recognized a gain of $135 million on these purchases, including broker fees and loan costs.
- Net proceeds from the sale of the notes in APA's new notes offering, after deducting the initial purchasers' discounts and estimated offering expenses, were approximately $839 million and used to fund in part APA's purchase of Apache notes in APA's cash tender offers.
- Each series of APA notes and debentures issued in settlement of the exchange and tender offers had the same interest rate, maturity date, and interest payment dates and the same optional redemption prices (if any) as the corresponding series of Apache notes and debentures for which they were exchanged.
- Each series of APA notes and debentures issued in settlement of the exchange and tender offers and new notes offering were fully and unconditionally guaranteed by Apache until the first time that the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures was less than $1 billion, which occurred in May 2025, after which Apache's guarantees were terminated in accordance with their terms on May 16, 2025.
- APA entered into two registration rights agreements pursuant to which APA agreed to register under the Securities Act of 1933, as amended, the notes and debentures that APA issued in the exchange and tender offers and new notes offering (collectively, the Unregistered Notes). On September 18, 2025, APA settled registered exchange offers for the Unregistered Notes, issuing registered notes and debentures in the same aggregate principal amount as the Unregistered Notes accepted for exchange and canceled and otherwise on terms substantially identical in all material respects to the applicable series of Unregistered Notes. Of the $3.6 billion aggregate principal amount of Unregistered Notes covered by the registered exchange offers, 99 percent was exchanged for registered notes and debentures, and the remaining Unregistered Notes remained outstanding.

Unsecured 2025 Committed Bank Credit Facilities

On January 15, 2025, the Company entered into two unsecured syndicated credit agreements for general corporate purposes:

- One agreement is denominated in US dollars (the 2025 USD Agreement) and provides for an unsecured five-year revolving credit facility for loans and letters of credit, with aggregate commitments of US$2.0 billion (including a letter of credit subfacility of up to US$750 million, of which US$250 million currently is committed). APA may increase commitments up to an aggregate US$2.5 billion by adding new lenders or obtaining the consent of any increasing existing lenders. This facility matures in January 2030, subject to the Company's two, one-year extension options.
- The second agreement is denominated in pounds sterling (the 2025 GBP Agreement) and provides for an unsecured five-year revolving credit facility, with aggregate commitments of £1.5 billion for loans and letters of credit. This facility matures in January 2030, subject to the Company's two, one-year extension options.

Apache guaranteed obligations under each of the 2025 USD Agreement and 2025 GBP Agreement (each, a 2025 Agreement) effective until the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures first was less than US$1.0 billion, which occurred in May 2025, after which Apache's guarantees were terminated in accordance with their terms on May 16, 2025.

The 2025 Agreements replaced on substantially the same terms two syndicated credit agreements that the Company entered in April 2022, one of which was denominated in US dollars with aggregate commitments of US$1.8 billion (the 2022 USD Agreement) and second of which was denominated in pounds sterling with aggregate commitments of £1.5 billion (the 2022 GBP Agreement). On January 15, 2025, the Company terminated commitments under both the 2022 USD Agreement and 2022 GBP Agreement in connection with entry into the 2025 Agreements.

As of December 31, 2025, there were no borrowings or letters of credit outstanding under the 2025 USD Agreement and no borrowings and an aggregate £1.0 million in letters of credit outstanding under the 2025 GBP Agreement. As of December 31, 2024, there were $10 million of borrowings and no letters of credit outstanding under the 2022 USD Agreement and no borrowings and an aggregate £303 million in letters of credit outstanding under the 2022 GBP Agreement.

All borrowings under the 2025 USD Agreement bear interest at one of two per annum rate options selected by the borrower, being either an alternate base rate (as defined), plus a margin varying from 0.0% to 0.675% (Base Rate Margin), or an adjusted term SOFR rate (as defined), plus a margin varying from 1.00% to 1.675% (Applicable Margin). All borrowings under the 2025 GBP Agreement bear interest with respect to any business day at an adjusted rate per annum determined by reference to the Sterling Overnight Index Average with respect to such business day published by the Bank of England, plus the Applicable Margin.

Each 2025 Agreement also requires the borrower to pay quarterly (i) a facility fee on total commitments at a per annum rate that varies from 0.125% to 0.325% and (ii) a commission on the face amount of each outstanding letter of credit at a per annum rate equal to the Applicable Margin then in effect. Customary letter of credit fronting fees and other charges are payable to issuing banks.

Margins and facility fees are at varying rates per annum determined by reference to the senior, unsecured, non-credit enhanced, long-term indebtedness for borrowed money of APA (Long-Term Debt Rating). The current Base Rate Margin is 0.30%, the Applicable Margin is 1.30%, and the facility fee is 0.20%.

Borrowers under each 2025 Agreement, which include certain subsidiaries of APA, may borrow, prepay, and reborrow loans and obtain letters of credit, and APA may obtain letters of credit for the account of its subsidiaries, in each case subject to representations and warranties, covenants, and events of default, such as:

- A financial covenant requires APA to maintain an adjusted debt-to-capital ratio of not greater than 65% at the end of any fiscal quarter.
- A negative covenant restricts the ability of APA and its subsidiaries to create liens securing debt on their hydrocarbon-related assets, with customary exceptions and exceptions for liens on subsidiary assets located outside of the U. S. and Canada; liens on assets also are permitted if debt secured thereby does not exceed 15% of APA's consolidated net tangible assets.
- Negative covenants restrict APA's ability to merge with another entity unless it is the surviving entity, a borrower's disposition of substantially all of its assets, prohibitions on the ability of certain subsidiaries to make payments to borrowers, and guarantees by APA or certain subsidiaries of debt of non-consolidated entities in excess of the stated threshold.
- Lenders may accelerate payment maturity and terminate lending and issuance commitments for nonpayment and other breaches; if a borrower or certain subsidiaries defaults on other indebtedness in excess of the stated threshold, has any unpaid, non-appealable judgment against it for payment of money in excess of the stated threshold, or has specified pension plan liabilities in excess of the stated threshold; or APA undergoes a specified change in control. Such acceleration and termination are automatic upon specified insolvency events of a borrower or certain subsidiaries.

The 2025 Agreements do not require collateral, do not have a borrowing base, do not permit lenders to accelerate maturity or refuse to lend based on unspecified material adverse changes, and do not have borrowing restrictions or prepayment obligations in the event of a decline in credit ratings.

The Company was in compliance with the terms of the 2025 Agreements as of December 31, 2025.

Uncommitted Lines of Credit

Each of the Company and Apache, from time to time, has and uses uncommitted credit and letter of credit facilities for working capital and credit support purposes. As of December 31, 2025 and 2024, there were no outstanding borrowings under these facilities. As of December 31, 2025, there were £901 million and $10 million in letters of credit outstanding under these facilities. As of December 31, 2024, there were £640 million and $11 million in letters of credit outstanding under these facilities.

Commercial Paper Program

The Company has a commercial paper program under which it from time to time may issue in private placements exempt from registration under the Securities Act short-term unsecured promissory notes (CP Notes) up to a maximum aggregate face amount of $2.0 billion outstanding at any time. The program was established in December 2023, and the maximum aggregate face amount of CP Notes issuable thereunder was increased to $2.0 billion from $1.8 billion on June 20, 2025. The maturities of CP Notes may vary but may not exceed 397 days from the date of issuance. Outstanding CP Notes are supported by available borrowing capacity under the Company's committed revolving credit facilities for general corporate purposes, which as of December 31, 2025, included the $2.0 billion 2025 USD Agreement.

Payment of CP Notes was unconditionally guaranteed on an unsecured basis by Apache, such guarantee effective until the first time that the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures was less than US$1.0 billion, which occurred in May 2025, after which Apache's guarantees were terminated in accordance with their terms on June 20, 2025.

The CP Notes are sold under customary market terms in the U.S. commercial paper market at a discount from par or at par and bear interest at rates determined at the time of issuance.

As of December 31, 2025, the Company had no CP Notes outstanding. As of December 31, 2024, the Company had $323 million in aggregate face amount of CP Notes outstanding, which was classified as long-term debt.

Unsecured Committed Term Loan Facility

On January 30, 2024, APA entered into a syndicated credit agreement providing for committed senior unsecured delayed-draw term loans to APA, the proceeds of which could be used to refinance certain indebtedness of Callon.

On April 1, 2024, APA acquired Callon and borrowed $1.5 billion under this credit agreement maturing April 1, 2027, of which $900 million remained outstanding as of December 31, 2024. APA fully prepaid this credit agreement on March 10, 2025. The repayment was partially financed with borrowings under APA's 2025 USD Agreement and commercial paper program.

9. INCOME TAXES

Net income before income taxes was composed of the following:

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
U.S.	$ 1,488	$ 705	$ 627
Foreign	1,303	830	2,256
Total	$ 2,791	$ 1,535	$ 2,883

The total income tax provision (benefit) consisted of the following:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Current income taxes:			
Federal	$ (104)	$ 76	$ 2
State	(1)	2	6
Foreign	844	1,075	1,330
	739	1,153	1,338
Deferred income taxes:			
Federal	384	(96)	(1,708)
State	41	3	(32)
Foreign	(65)	(643)	78
	360	(736)	(1,662)
Total	$ 1,099	$ 417	$ (324)

The total income tax provision differs from the amounts computed by applying the U.S. statutory income tax rate to income (loss) before income taxes. A reconciliation of the tax on the Company's net income before income taxes and total income tax provision (benefit) is shown below:

	For the Year Ended December 31,					
	2025		2024		2023	
	Amount	% of Income Before Income Taxes	Amount	% of Income Before Income Taxes	Amount	% of Income Before Income Taxes
	(In millions)					
U.S. federal statutory tax rate	$ 586	21.0 %	$ 322	21.0 %	$ 605	21.0 %
State and local income taxes, net of federal income tax effect[1]	31	1.1 %	2	0.1 %	(23)	(0.8)%
Foreign tax effects:						
Egypt:						
Statutory tax rate difference between Egypt and U.S.	277	9.9 %	334	21.8 %	366	12.7 %
Concessions on production-sharing contracts	75	2.8 %	77	5.0 %	65	2.3 %
U.K.:						
Statutory tax rate difference between U.K. and U.S.	4	0.1 %	(376)	(24.5)%	283	9.8 %
Enacted changes in tax law	78	2.8 %	—	— %	174	6.0 %
Annual Energy Profits Levy deferred adjustment	30	1.1 %	200	13.0 %	78	2.7 %
Accretion expense	44	1.6 %	37	2.4 %	27	0.9 %
Financing activities	(43)	(1.5)%	(46)	(3.0)%	(39)	(1.3)%
Changes in valuation allowances	23	0.8 %	—	— %	—	— %
Other	—	— %	5	0.3 %	(40)	(1.4)%
Suriname:						
Statutory tax rate difference between Suriname and U.S.	(5)	(0.2)%	(13)	(0.8)%	(8)	(0.3)%
Changes in valuation allowances	(8)	(0.3)%	18	1.2 %	10	0.4 %
Other	20	0.7 %	13	0.8 %	9	0.3 %
Other foreign jurisdictions	10	0.4 %	9	0.6 %	9	0.3 %
Cross-border tax laws	1	— %	1	0.1 %	1	— %
Tax credits:						
Corporate alternative minimum tax credit	71	2.5 %	(74)	(4.8)%	—	— %
Other tax credits	(1)	— %	(3)	(0.2)%	—	— %
Foreign tax credits	269	9.6 %	—	— %	—	— %
Changes in valuation allowances	(273)	(9.8)%	—	— %	(1,852)	(64.2)%
Non-taxable or non-deductible items:						
Stock compensation	1	— %	17	1.1 %	(2)	(0.1)%
Legal reserves	—	— %	14	0.9 %	—	— %
Transaction costs	—	— %	5	0.3 %	—	— %
U.S tax basis of investment in U.K.	—	— %	(214)	(13.9)%	—	— %
Other	(1)	— %	10	0.7 %	8	0.3 %
Changes in unrecognized tax benefits	(16)	(0.6)%	2	0.1 %	5	0.2 %
Other adjustments:						
Corporate alternative minimum tax	(71)	(2.5)%	74	4.8 %	—	— %
Other adjustments	(3)	(0.1)%	3	0.2 %	—	— %
Total income tax provision (benefit)	$ 1,099	39.4 %	$ 417	27.2 %	$ (324)	(11.2)%

(1) Taxes in Texas and New Mexico represented greater than 50 percent of the total state and local income tax effect.

The net deferred income tax asset reflects the net tax impact of temporary differences between the asset and liability amounts carried on the balance sheet under GAAP and amounts utilized for income tax purposes. The net deferred income tax asset consisted of the following as of December 31:

	2025	2024
	(In millions)	
Deferred tax assets:		
U.S. and state net operating losses	$ 2,298	$ 2,487
Capital losses	13	14
Foreign net operating losses	76	55
Tax credits and other tax incentives	36	105
Foreign tax credits	1,935	2,204
Accrued expenses and liabilities	96	76
Asset retirement obligation	1,021	952
Property and equipment	16	45
Equity investments	1	1
Net interest expense limitation	130	287
Lease liability	93	114
Decommissioning contingency for sold Gulf of America properties	200	232
Other	51	—
Total deferred tax assets	5,966	6,572
Valuation allowance	(2,401)	(2,623)
Net deferred tax assets	3,565	3,949
Deferred tax liabilities:		
Property and equipment	1,108	1,060
Right-of-use asset	87	111
Decommissioning security for sold Gulf of America properties	9	40
Other	33	49
Total deferred tax liabilities	1,237	1,260
Net deferred income tax asset	$ 2,328	$ 2,689

Net deferred tax assets and liabilities are included in the consolidated balance sheet as of December 31 as follows:

	2025	2024
	(In millions)	
Assets:		
Other assets		
Deferred tax asset	$ 2,328	$ 2,703
Liabilities:		
Deferred credits and other noncurrent liabilities		
Deferred tax liability	—	14
Net deferred income tax asset	$ 2,328	$ 2,689

On April 1, 2024, the Company completed its acquisition of Callon in an all-stock transaction. The Company's deferred tax asset increased by approximately $565 million as part of the assets assumed through the Callon acquisition. Refer to Note 2— Acquisitions and Divestitures for further detail.

On January 10, 2023, Finance Act 2023 was enacted, receiving Royal Assent, and included amendments to the Energy (Oil and Gas) Profits Levy Act of 2022 (the Energy Profits Levy), increasing the levy from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023 through March 31, 2028. On March 20, 2025, Finance Act 2025 was enacted, receiving Royal Assent, and included further amendments to the Energy Profits Levy, increasing the levy from a 35 percent rate to a 38 percent rate, among other changes, effective for the period of November 1, 2024 through March 31, 2030. Under U.S. GAAP, the financial statement impact of new legislation is recorded in the period of enactment. As a result, the Company recorded tax expense of $78 million and $174 million related to the change in tax law in 2025 and 2023, respectively.

On August 16, 2022, the U.S. enacted the Inflation Reduction Act of 2022 (IRA). The IRA includes a new 15 percent corporate alternative minimum tax (CAMT) on applicable corporations with an average annual adjusted financial statement income that exceeds $1.0 billion for any three consecutive years preceding the tax year at issue. The CAMT is effective for tax years beginning after December 31, 2022. The Company became an applicable corporation subject to CAMT beginning on January 1, 2024. On September 12, 2024, the U.S. Department of Treasury and the Internal Revenue Service released proposed regulations relating to the application and implementation of CAMT. In 2025, the Company recorded a current tax benefit of $71 million related to the 2024 return-to-accrual adjustment, with an offsetting deferred tax expense of the same amount for the change in CAMT credits.

On July 4, 2025, the U.S. enacted the One Big Beautiful Bill Act of 2025 (OBBBA). Among other changes, the OBBBA expanded and made permanent 100 percent bonus depreciation for eligible assets acquired and placed in service after January 19, 2025, and aligned the treatment of intangible drilling costs for CAMT purposes with regular tax treatment starting in 2026. OBBBA did not have a material impact on total tax expense for the year ended December 31, 2025, as impacts to current tax expense are offset by impacts to deferred tax expense. In 2025, the law change resulted in a current tax benefit of $42 million fully offset by a deferred tax expense of the same amount.

On September 30, 2025, the Internal Revenue Service issued further interim guidance on CAMT. Among other changes, the guidance provided for a reduction to CAMT related to net operating loss utilization for regular federal income tax purposes. This guidance did not have a material impact on total tax expense for the year ended December 31, 2025, as impacts to current tax expense are offset by impacts to deferred tax expense. In 2025, the guidance resulted in a current tax benefit of $72 million, fully offset by a deferred tax expense of the same amount.

In December 2021, the Organisation for Economic Co-operation and Development issued Pillar Two Model Rules introducing a new global minimum tax of 15 percent on a country-by-country basis, with certain aspects effective in certain jurisdictions on January 1, 2024. Although the Company continues to monitor enacted legislation to implement these rules in countries where the Company could be impacted, the Company does not expect that the Pillar Two framework will have a material impact on its consolidated financial statements.

Deferred tax assets are recorded for future deductible amounts and certain other tax benefits, such as net operating losses, tax credits and other tax attributes, provided that the Company assesses the utilization of such assets to be “more likely than not.” The Company assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to realize the existing deferred tax assets. Based on this assessment, the Company has recorded valuation allowances for certain net operating losses, foreign tax credits and capital loss carryforwards that it does not believe are more likely than not to be realized.

During the fourth quarter of 2023, as a result of increases in projections of future taxable income and the absence of objective negative evidence such as a cumulative loss in recent years, the Company determined there was sufficient positive evidence to release a majority of the U.S. valuation allowance, which resulted in a non-cash deferred income tax benefit of $1.7 billion.

In 2025, 2024, and 2023, the Company's valuation allowance decreased by $222 million, $7 million and $2.3 billion, respectively, as detailed in the table below:

	2025	2024	2023
		(In millions)	
Balance at beginning of year	$ 2,623	$ 2,630	$ 4,918
State[1]	33	(51)	(63)
U.S.	(270)	26	(2,235)
Foreign	15	18	10
Balance at end of year	$ 2,401	$ 2,623	$ 2,630

(1) Reported as a component of state income taxes.

On December 31, 2025, the Company had net operating losses as follows:

	Amount	Expiration
	(In millions)	
U.S.	$ 9,463	2029 - Indefinite
State	6,523	Various
Foreign	211	2026 - Indefinite

The Company has a U.S. net operating loss carryforward of $9.5 billion, which includes $2.1 billion of net operating loss subject to annual limitation under Section 382 of the Internal Revenue Code (Code). Net operating losses generated in tax years beginning after 2017 are subject to an 80 percent taxable income limitation with indefinite carryover under the 2017 Tax Cuts and Jobs Act. The Company also has state net operating losses of $6.5 billion, foreign net operating losses of $211 million, and a net interest expense carryover of $607 million under Section 163(j) of the Code with indefinite carryover. The Company has recorded a valuation allowance against some of the U.S. net operating losses, the state net operating losses, the foreign net operating losses, and the U.S. capital loss because it is more likely than not that these net operating losses and the capital loss carryforward will not be realized. The Company believes it is more likely than not that the deferred tax assets related to the remaining U.S. net operating losses and the net interest expense carryover will be utilized prior to their expiration.

On December 31, 2025, the Company had foreign tax credits as follows:

	Amount	Expiration
	(In millions)	
Foreign tax credits	$ 1,935	2026

The Company has a $1.9 billion U.S. foreign tax credit carryforward. The Company has recorded a valuation allowance against the U.S. foreign tax credits listed above because it is more likely than not that these attributes will expire unutilized.

The Company accounts for income taxes in accordance with ASC Topic 740, "Income Taxes," which prescribes a minimum recognition threshold a tax position must meet before being recognized in the financial statements. Tax positions generally refer to a position taken in a previously filed income tax return or expected to be included in a tax return to be filed in the future that is reflected in the measurement of current and deferred income tax assets and liabilities. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2025	2024	2023
		(In millions)	
Balance at beginning of year	$ 89	$ 93	$ 89
Additions based on tax positions related to prior year	—	1	4
Reductions for tax positions of prior years	(25)	(5)	—
Balance at end of year	$ 64	$ 89	$ 93

The Company records interest and penalties related to unrecognized tax benefits as a component of income tax expense. Each quarter, the Company assesses the amounts provided for and, as a result, may increase or reduce the amount of interest and penalties. During the year ended December 31, 2025, the Company recorded an income tax benefit of $8.2 million for interest and penalties. In each of the years ended December 31, 2024 and 2023, the Company recorded tax expense of $2 million, respectively, for interest and penalties. At December 31, 2025, 2024, and 2023, the Company had an accrued liability for interest and penalties of nil, $9 million, and $7 million, respectively.

Income taxes paid (net of refunds) for the year ended December 31, 2025 were as follows:

	Amount (In millions)
U.S. Federal	$ 92
U.S. State and Local	(15)
Foreign:	
Egypt	650
U.K.	272
Foreign subtotal	922
Total	$ 999

The Company and its subsidiaries are subject to U.S. federal income tax as well as income tax in various states and foreign jurisdictions. The Company's uncertain tax positions are related to tax years that may be subject to examination by the relevant taxing authority. The Company's earliest open tax years in its key jurisdictions are as follows:

Jurisdiction	
U.S.	2014
Egypt	2007
U.K.	2022

10. COMMITMENTS AND CONTINGENCIES

Legal Matters

The Company is party to various legal actions arising in the ordinary course of business, including litigation and governmental and regulatory controls, which also may include controls related to the potential impacts of climate change. As of December 31, 2025, the Company has an accrued liability of approximately $23 million for all legal contingencies that are deemed to be probable of occurring and can be reasonably estimated. The Company's estimates are based on information known about the matters and its experience in contesting, litigating, and settling similar matters. Although actual amounts could differ from management's estimate, none of the actions are believed by management to involve future amounts that would be material to the Company's financial position, results of operations, or liquidity after consideration of recorded accruals. With respect to material matters for which the Company believes an unfavorable outcome is reasonably possible, the Company has disclosed the nature of the matter and a range of potential exposure, unless an estimate cannot be made at this time. It is management's opinion that the loss for any other litigation matters and claims that are reasonably possible to occur will not have a material adverse effect on the Company's financial position, results of operations, or liquidity.

Australian Operations Divestiture Dispute

Pursuant to a Sale and Purchase Agreement dated April 9, 2015 (Quadrant SPA), the Company and its subsidiaries divested Australian operations to Quadrant Energy Pty Ltd (Quadrant). Closing occurred on June 5, 2015. In April 2017, the Company filed suit against Quadrant for breach of the Quadrant SPA. In its suit, the Company seeks approximately AUD $80 million. In December 2017, Quadrant filed a defense of equitable set-off to the Company's claim and a counterclaim seeking approximately AUD $200 million in the aggregate. In 2018, Quadrant was acquired by Australian oil and gas company Santos, Ltd., who assumed Quadrant's place in the ongoing litigation. In early 2025, Santos amended the pending counterclaims to abandon a number of claims that had been asserted against the Company but maintaining counterclaims for approximately AUD $57 million. Santos then filed a new lawsuit in the Supreme Court of Western Australia contending that it may be liable to the Australian Taxation Office for assessments, penalties, and interest related to the 2014 and 2015 tax years of approximately AUD $133 million and asserting that, if such amounts must be paid, the Company is liable to Santos for those amounts under the Quadrant SPA. All lawsuits related to the Quadrant SPA have now been consolidated into the same proceeding. The Company will vigorously prosecute its claim while vigorously defending against any counterclaims.

Delaware Litigation

On September 10, 2020, the State of Delaware filed suit, individually and on behalf of the people of the State of Delaware, against over 25 oil and gas companies alleging damages as a result of global warming. Plaintiffs seek unspecified damages and abatement under various tort theories. The Company is vigorously defending the suit.

Kulp Minerals Lawsuit

On or about April 7, 2023, Apache was sued in a purported class action in New Mexico styled Kulp Minerals LLC v. Apache Corporation, Case No. D-506-CV-2023-00352 in the Fifth Judicial District. The Kulp Minerals case was not certified and sought to represent a group of owners allegedly owed statutory interest under New Mexico law as a result of purported late oil and gas payments. On December 5, 2025, the plaintiff voluntarily dismissed the case with prejudice.

Environmental Matters

As of December 31, 2025, the Company had an undiscounted reserve for environmental remediation of approximately $2 million.

The Company is not aware of any environmental claims existing as of December 31, 2025, that have not been provided for or would otherwise have a material impact on its financial position, results of operations, or liquidity. There can be no assurance, however, that current regulatory requirements will not change or past non-compliance with environmental laws will not be discovered on the Company's properties.

Potential Decommissioning Obligations on Sold Properties

In 2013, Apache sold its Gulf of America (GOA) Shelf operations and properties and its GOA operating subsidiary, GOM Shelf LLC (GOM Shelf) to Fieldwood Energy LLC (Fieldwood). Fieldwood assumed the obligation to decommission the properties held by GOM Shelf and the properties acquired from Apache and its other subsidiaries (collectively, the Legacy GOA Assets). On February 14, 2018, Fieldwood filed for (and subsequently emerged from) Chapter 11 bankruptcy protection. On August 3, 2020, Fieldwood filed for (and subsequently emerged from) Chapter 11 bankruptcy protection for a second time. Upon emergence from this second bankruptcy, the Legacy GOA Assets were separated into a standalone company, which was subsequently merged into GOM Shelf. Under GOM Shelf's limited liability company agreement, the proceeds of production of the Legacy GOA Assets are to be used to fund the operation of GOM Shelf and the decommissioning of Legacy GOA Assets. The decommissioning obligations for the Legacy GOA Assets are partially secured by a trust account of which Apache is a beneficiary and which is funded by net profits interests (NPIs) depending on future oil prices. In addition, after such sources have been exhausted, Apache agreed upon resolution of GOM Shelf's second bankruptcy to loan GOM Shelf up to $400 million to perform decommissioning, with such loans and related obligations secured by first and prior liens on the Legacy GOA Assets.

By letter dated April 5, 2022 (replacing two earlier letters) and by subsequent letter dated March 1, 2023, GOM Shelf notified the Bureau of Safety and Environmental Enforcement (BSEE) that it was unable to fund the decommissioning obligations that it was obligated to perform on certain of the Legacy GOA Assets. As a result, Apache and other current and former owners in these assets have received orders from BSEE and demands from third parties to decommission certain of the Legacy GOA Assets included in GOM Shelf's notifications to BSEE. Apache expects to receive similar orders and demands on the other Legacy GOA Assets included in GOM Shelf's notification letters. Apache has also received orders to decommission other Legacy GOA Assets that were not included in GOM Shelf's notification letters. Further, Apache anticipates that GOM Shelf may send additional such notices to BSEE in the future and that it may receive additional orders from BSEE requiring it to decommission other Legacy GOA Assets.

As of December 31, 2025, the Company recorded an asset of $40 million representing the remaining amount the Company expects to be reimbursed from remaining security related to these decommissioning costs. Of the total asset recorded as of December 31, 2025, $21 million is reflected under the caption "Decommissioning security for sold Gulf of America properties," and $19 million is reflected under "Other current assets" in the Company's consolidated balance sheet.

As of December 31, 2025, Apache estimates that its potential liability to fund the remaining decommissioning of Legacy GOA Assets and assets previously sold to other operators ranges from $0.9 billion to $1.2 billion on an undiscounted basis. Management does not believe any specific estimate within this range is a better estimate than any other. Accordingly, the Company recorded contingent liabilities in the amounts of $881 million and $1.0 billion as of December 31, 2025, and December 31, 2024, respectively. Of the total liability recorded as of December 31, 2025, $782 million is reflected under the caption "Decommissioning contingency for sold Gulf of America properties" and $99 million is reflected under "Other current liabilities" in the Company's consolidated balance sheet. Changes in significant assumptions impacting Apache's estimated liability, including expected well decommissioning spread rates, derrick barge rates, planned abandonment logistics, and future cash flows of GOM Shelf, could result in a liability in excess of the amount accrued.

The Company recognized $60 million of gains on previously sold Gulf of America properties during 2025 to reflect the net impact of decreased estimated decommissioning costs of Legacy GOA Assets which BSSE may order the Company to decommission. The Company recognized losses on previously sold Gulf of America properties of $273 million and 212 million during 2024 and 2023, respectively, in the Company's statement of consolidated operations.

Leases and Contractual Obligations

The Company determines if an arrangement is an operating or finance lease at the inception of each contract. If the contract is classified as an operating lease, the Company records a Right-of-Use (ROU) asset and corresponding liability reflecting the total remaining present value of fixed lease payments over the expected term of the lease agreement. The expected term of the lease may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. If the Company's lease does not provide an implicit rate in the contract, the Company uses its incremental borrowing rate when calculating the present value. In the normal course of business, the Company enters into various lease agreements for real estate, drilling rigs, vessels, aircrafts, and equipment related to its exploration and development activities, which are typically classified as operating leases under the provisions of the standard. ROU assets are reflected within "Deferred charges and other assets" on the Company's consolidated balance sheet, and the associated operating lease liabilities are reflected within "Other current liabilities" and "Other" within "Deferred Credits and Other Noncurrent Liabilities," as applicable.

Operating lease expense associated with ROU assets is recognized on a straight-line basis over the lease term. Lease expense is reflected on the statement of consolidated operations commensurate with the leased activities and nature of the services performed. Gross fixed operating lease expense, inclusive of amounts billable to partners and other working interest owners, was $148 million, $170 million, and $168 million for the years ended 2025, 2024, and 2023, respectively. As allowed under the standard, the Company accounts for non-lease and lease components as a single lease component for all asset classes and has elected to exclude short-term leases (those with terms of 12 months or less) from the balance sheet presentation. Costs incurred for short-term leases were $69 million, $85 million, and $71 million in 2025, 2024, and 2023, respectively. In 2025 and 2024, these costs primarily related to short term drilling rigs in the U.S. and decommissioning work in the Gulf of America. In 2023 these costs primarily related to decommissioning work in the Gulf of America.

Finance lease assets are included in "Property and Equipment" on the consolidated balance sheet, and the associated finance lease liabilities are reflected within "Current debt" and "Long-term debt," as applicable. Depreciation on the Company's finance lease asset was $2 million in each of the years 2025, 2024, and 2023. Interest on the Company's finance lease liability was $1 million in each of the years 2025, 2024, and 2023.

The following table represents the Company's weighted average lease term and discount rate as of December 31, 2025:

	Operating Leases	Finance Lease
Weighted average remaining lease term	6.8 years	7.7 years
Weighted average discount rate	5.9 %	4.4 %

At December 31, 2025, contractual obligations for long-term operating leases, finance leases, and purchase obligations are as follows:

Net Minimum Commitments[1]	Operating Leases[2]	Finance Lease[3]	Purchase Obligations[4]
		(In millions)	
2026	$ 103	$ 4	$ 243
2027	70	4	214
2028	53	4	182
2029	41	4	156
2030	25	4	119
Thereafter	136	14	57
Total future minimum payments	428	34	$ 971
Less: imputed interest	(111)	(6)	N/A
Total lease liabilities	317	28	N/A
Current portion	97	3	N/A
Non-current portion	$ 220	$ 25	N/A

(1) Excludes commitments for jointly owned fields and facilities for which the Company is not the operator.

(2) Amounts represent future payments associated with oil and gas operations inclusive of amounts billable to partners and other working interest owners. Such payments may be capitalized as a component of oil and gas properties and subsequently depreciated, impaired, or written off as exploration expense.

(3) Amounts represent the Company's finance lease obligation related to the Company's Midland, Texas regional office building.

(4) Amounts represent any agreements to purchase goods or services that are enforceable and legally binding and that specify all significant terms. These include minimum commitments associated with take-or-pay contracts, NGL processing agreements, drilling work program commitments, and agreements to secure capacity rights on third-party pipelines. Amounts exclude certain product purchase obligations related to marketing and trading activities for which there are no minimum purchase requirements or the amounts are not fixed or determinable. Total costs incurred under take-or-pay and throughput obligations were $263 million, $245 million, and $182 million in 2025, 2024, and 2023, respectively.

The lease liability reflected in the table above represents the Company's fixed minimum payments that are settled in accordance with the lease terms. Actual lease payments during the period may also include variable lease components such as common area maintenance, usage-based sales taxes and rate differentials, or other similar costs that are not determinable at the inception of the lease. Gross variable lease payments, inclusive of amounts billable to partners and other working interest owners were $52 million, $48 million, and $74 million in 2025, 2024, and 2023, respectively.

11. RETIREMENT AND DEFERRED COMPENSATION PLANS

The Company provides retirement benefits to its U.S. employees through the use of multiple plans: a 401(k) savings plan, a money purchase retirement plan, a non-qualified retirement savings plan, and a non-qualified restorative retirement savings plan. The 401(k) savings plan provides participating employees the ability to elect to contribute up to 50 percent of eligible compensation to the plan with the Company making matching contributions up to a maximum of 8 percent of each employee's annual eligible compensation. In addition, the Company contributes 6 percent of each participating employee's annual eligible compensation to a money purchase retirement plan. The 401(k) savings plan and the money purchase retirement plan are subject to certain annually-adjusted, government-mandated restrictions that limit the amount of employee and Company contributions. For certain eligible employees, the Company also provides a non-qualified retirement savings plan or a non-qualified restorative retirement savings plan. These plans allow the deferral of up to 50 percent of each employee's base salary, up to 75 percent of each employee's annual bonus (that accepts employee contributions) and the Company's matching contributions in excess of the government mandated limitations imposed in the 401(k) savings plan and money purchase retirement plan.

Vesting in the Company's contributions in the 401(k) savings plan, the money purchase retirement plan, the non-qualified retirement savings plan and the non-qualified restorative retirement savings plan occurs at the rate of 20 percent for every completed year of employment. Upon a change in control of ownership of APA, immediate and full vesting occurs.

The aggregate annual cost to the Company of all U.S. and international savings plans, the money purchase retirement plan, non-qualified retirement savings plan, and non-qualified restorative retirement savings plan was $44 million, $46 million, and $44 million for 2025, 2024, and 2023, respectively.

The Company also provides a funded noncontributory defined benefit pension plan (U.K. Pension Plan) covering certain employees of the Company's North Sea operations in the U.K. The plan provides defined pension benefits based on years of service and final salary. The plan applies only to employees who were part of BP North Sea's pension plan as of April 2, 2003, prior to the acquisition of BP North Sea by the Company effective July 1, 2003.

Additionally, the Company offers postretirement medical benefits to U.S. employees who meet certain eligibility requirements. Eligible participants receive medical benefits up until the age of 65 or at the date they become eligible for Medicare, provided the participant remits the required portion of the cost of coverage. The plan is contributory with participants' contributions adjusted annually. The postretirement benefit plan does not cover benefit expenses once a covered participant becomes eligible for Medicare.

The following tables set forth the benefit obligation, fair value of plan assets and funded status as of December 31, 2025, 2024, and 2023, and the underlying weighted average actuarial assumptions used for the U.K. Pension Plan and U.S. postretirement benefit plan. The Company uses a measurement date of December 31 for its pension and postretirement benefit plans.

	2025		2024		2023	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Change in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	$ 107	$ 15	$ 118	$ 15	$ 108	$ 15
Service cost	1	1	1	1	1	1
Interest cost	6	1	6	1	5	1
Foreign currency exchange rates	8	—	(2)	—	6	—
Actuarial losses (gains)	(1)	(1)	(11)	—	3	—
Plan curtailments	—	—	—	(1)	—	—
Benefits paid	(6)	(2)	(5)	(2)	(5)	(3)
Retiree contributions	—	1	—	1	—	1
Projected benefit obligation at end of year	115	15	107	15	118	15
Change in Plan Assets						
Fair value of plan assets at beginning of year	136	—	150	—	137	—
Actual return (loss) on plan assets	5	—	(8)	—	8	—
Foreign currency exchange rates	10	—	(3)	—	8	—
Employer contributions	2	1	2	1	2	1
Benefits paid	(6)	(2)	(5)	(2)	(5)	(3)
Retiree contributions	—	1	—	1	—	2
Fair value of plan assets at end of year	147	—	136	—	150	—
Funded status at end of year	$ 32	$ (15)	$ 29	$ (15)	$ 32	$ (15)
Amounts recognized in Consolidated Balance Sheet						
Current liability	$ —	$ (1)	$ —	$ (2)	$ —	$ (2)
Non-current asset (liability)	32	(14)	29	(13)	32	(13)
	$ 32	$ (15)	$ 29	$ (15)	$ 32	$ (15)
Pre-tax Amounts Recognized in Accumulated Other Comprehensive Income (Loss)						
Accumulated gain (loss)	$ (18)	$ 14	$ (16)	$ 14	$ (12)	$ 16
Weighted Average Assumptions used as of December 31						
Discount rate	5.60 %	5.18 %	5.60 %	5.49 %	4.80 %	5.00 %
Salary increases	4.50 %	N/A	4.70 %	N/A	4.60 %	N/A
Expected return on assets	5.60 %	N/A	5.70 %	N/A	4.80 %	N/A
Healthcare cost trend						
Initial	N/A	7.00 %	N/A	6.50 %	N/A	6.25 %
Ultimate in 2035	N/A	5.25 %	N/A	5.25 %	N/A	5.25 %

As of December 31, 2025, 2024, and 2023, the accumulated benefit obligation for the U.K. Pension Plan was $111 million, $102 million, and $112 million, respectively.

The Company's defined benefit pension plan assets are held by a non-related trustee who has been instructed to invest the assets under a cash flow driven investment strategy. The Company intends to invest in primarily low risk debt securities that will provide a reasonable rate of return focused on cash flow timing such that the benefits promised to members are provided when due. The U.K. Pension Plan policy is to target an ongoing funding level of 100 percent through prudent investments and includes policies and strategies such as investment goals, risk management practices, and permitted and prohibited investments. A breakout of allocations for the Company's plan asset holdings are summarized below:

	Percentage of Plan Assets at Year-End	
	2025	2024
Asset Category		
Multi-asset credit	61 %	62 %
Nominal bonds	3 %	4 %
Inflation-linked bonds	36 %	33 %
Cash	— %	1 %
Total	100 %	100 %

The plan's assets do not include any direct ownership of equity or debt securities of the Company. The fair value of plan assets at December 31, 2025 and 2024 are based upon unadjusted quoted prices for identical instruments in active markets, which is a Level 1 fair value measurement. The following table presents the fair values of plan assets for each major asset category based on the nature and significant concentration of risks in plan assets as follows:

	December 31,	
	2025	2024
	(In millions)	
Asset Category		
Multi-asset credit	90	84
Nominal bonds	3	6
Inflation-linked bonds	53	45
Cash	1	1
Total	$ 147	$ 136

The expected long-term rate of return on assets assumptions are derived relative to the yield on long-dated fixed-interest bonds issued by the U.K. government (gilts). For equities, outperformance relative to gilts is assumed to be 1.3 percent per year.

The following tables set forth the components of the net periodic cost and the underlying weighted average actuarial assumptions used for the pension and postretirement benefit plans as of December 31 as follows:

	2025		2024		2023	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Components of Net Periodic Benefit Cost						
Service cost	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Interest cost	6	1	6	1	5	1
Expected return on assets	(8)	—	(7)	—	(7)	—
Amortization of actuarial gain	—	(2)	—	(2)	—	(2)
Curtailment gain	—	—	—	(1)	—	—
Net periodic benefit cost	$ (1)	$ —	$ —	$ (1)	$ (1)	$ —
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost for the Years Ended December 31						
Discount rate	5.60 %	5.49 %	4.80 %	5.00 %	5.00 %	5.29 %
Salary increases	4.70 %	N/A	4.60 %	N/A	4.70 %	N/A
Expected return on assets	5.70 %	N/A	4.80 %	N/A	4.70 %	N/A
Healthcare cost trend						
Initial	N/A	6.50 %	N/A	6.25 %	N/A	6.50 %
Ultimate in 2032	N/A	5.25 %	N/A	5.25 %	N/A	5.25 %

The Company expects to contribute approximately $1 million to its pension plan and $1 million to its postretirement benefit plan in 2026. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Postretirement Benefits
	(In millions)	
2026	$ 5	$ 1
2027	7	1
2028	7	1
2029	7	1
2030	7	1
Years 2031-2035	39	7

12. CAPITAL STOCK

Common Stock Outstanding

The following table provides changes to the Company's common shares outstanding for the years ended December 31, 2025, 2024, and 2023:

	For the Year Ended December 31,		
	2025	2024	2023
Balance, beginning of year	365,397,149	303,575,901	311,559,149
Shares issued for stock-based compensation plans:			
Treasury shares issued	—	—	2,016
Common shares issued	458,481	70,983,745	725,914
Treasury shares acquired	(12,890,984)	(9,162,497)	(8,711,178)
Balance, end of year	352,964,646	365,397,149	303,575,901

Net Income per Common Share

The following table provides a reconciliation of the components of basic and diluted net income per common share for the years ended December 31, 2025, 2024, and 2023:

	2025			2024			2023		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
	(In millions, except per share amounts)								
Basic:									
Income attributable to common stock	$ 1,434	359	$ 3.99	$ 804	353	$ 2.28	$ 2,855	308	$ 9.26
Effect of Dilutive Securities:									
Stock compensation awards	$ —	—	$ —	$ —	—	$ (0.01)	$ —	1	$ (0.01)
Diluted:									
Income attributable to common stock	$ 1,434	359	$ 3.99	$ 804	353	$ 2.27	$ 2,855	309	$ 9.25

The diluted EPS calculation excludes options and restricted shares that were anti-dilutive totaling 3.3 million, 2.0 million, and 1.9 million for the years ended December 31, 2025, 2024, and 2023, respectively.

Stock Repurchase Program

During the fourth quarter of 2021, the Company's Board of Directors authorized the purchase of 40 million shares of the Company's common stock. During the third quarter of 2022, the Company's Board of Directors authorized the purchase of an additional 40 million shares of the Company's common stock.

During 2025, the Company repurchased 12.9 million shares at an average price of $21.73 per share, and as of December 31, 2025, the Company had remaining authorization to repurchase 21.9 million shares. During 2024, the Company repurchased 9.2 million shares at an average price of $26.83 per share. During 2023, the Company repurchased 8.7 million shares at an average price of $37.81 per share.

The Company is not obligated to acquire any additional shares. Shares may be purchased either in the open market or through privately held negotiated transactions.

Common Stock Dividend

For the years ended December 31, 2025, 2024, and 2023, the Company declared common stock dividends totaling $1.00 per share.

Stock Compensation Plans

The Company maintains several stock-based compensation plans, which include stock options, restricted stock, and conditional restricted stock unit plans.

On May 12, 2016, the Company's shareholders approved the 2016 Omnibus Compensation Plan (the 2016 Plan), which is used to provide eligible employees with equity-based incentives by granting incentive stock options, non-qualified stock options, performance awards, restricted stock awards, restricted stock units, stock appreciation rights, cash awards, or any combination of the foregoing. As of December 31, 2025, 5.2 million shares were authorized and available for grant under the 2016 Plan. Previously approved plans remain in effect solely for the purpose of governing grants still outstanding that were issued prior to approval of the 2016 Plan. All new grants are issued from the 2016 Plan. In 2018, the Company began issuing cash-settled awards (phantom units) under the restricted stock and conditional restricted stock unit plans. The phantom units represent a hypothetical interest in the Company's stock and, once vested, are settled in cash.

Costs related to the plans are capitalized or expensed to "Lease operating expenses," "Exploration," or "General and administrative" in the Company's statement of consolidated operations based on the nature of each employee's activities. The following table summarizes the Company's stock-settled and cash-settled compensation costs for the years ended December 31, 2025, 2024, and 2023:

	For the Year Ended December 31,		
	2025	2024	2023
	(In millions)		
Stock-settled and cash-settled compensation expensed:			
Lease operating expenses	$ 26	$ 16	$ 27
Exploration	7	4	7
General and administrative	74	29	50
Total stock-settled and cash-settled compensation expensed	107	49	84
Stock-settled and cash-settled compensation capitalized	15	9	13
Total stock-settled and cash-settled compensation costs	$ 122	$ 58	$ 97

Stock Options

As of December 31, 2025, the Company had outstanding options to purchase shares of its common stock under the 2016 Plan and the 2011 Omnibus Equity Compensation Plan (the 2011 Plan and, with the 2016 Plan, the Omnibus Plans). The Omnibus Plans were submitted to and approved by the Company's shareholders. New shares of common stock will be issued for employee stock option exercises. Under the Omnibus Plans, the exercise price of each option equals the closing price of APA's common stock on the date of grant. Options granted become exercisable ratably over a three-year period and expire 10 years after granted.

During the year ended December 31, 2025, compensation costs related to stock options charged to expense and capitalized were $8 million and $1 million, respectively.

The following table summarizes stock option activity for the years ended December 31, 2025, 2024, and 2023:

	2025		2024		2023	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
	(In thousands, except exercise price amounts)					
Outstanding, beginning of year	1,416	$ 48.64	1,465	$ 48.48	2,078	$ 57.71
Granted	1,722	23.26	—	—	—	—
Exercised	—	—	—	—	(12)	42.38
Forfeited	(224)	22.86	—	—	—	—
Expired	(139)	48.47	(49)	43.91	(601)	80.53
Outstanding, end of year[1]	2,775	34.98	1,416	48.64	1,465	48.48
Expected to vest	1,427	23.33	—	—	—	—
Exercisable, end of year[1][2]	1,348	47.30	1,416	48.64	1,465	48.48

(1) As of December 31, 2025, options exercisable had a weighted average remaining contractual life of 1.5 years and $97 thousand aggregate intrinsic value and options outstanding had a weighted average remaining contractual life of 5.4 years and $2 million aggregate intrinsic value.

(2) As of December 31, 2025, there was $6 million of total unrecognized compensation cost related to 1,426,518 unvested stock options.

During the year ended December 31, 2025, there were 1,721,990 options issued and no options exercised. During the year ended December 31, 2024, there were no options issued or exercised. During the year ended December 31, 2023, there were no options issued and 12,183 options exercised.

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model. Assumptions used in the valuation are disclosed in the following table. Expected volatilities are based on historical volatility of the Company's common stock and other factors. The expected dividend yield is based on historical yields on the date of grant. The expected term of stock options granted represents the period of time that the stock options are expected to be outstanding and is derived from historical exercise behavior, current trends, and values derived from lattice-based models. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant.

	2025	2024	2023
Expected volatility	57.37 %	N/A	N/A
Expected dividend yields	4.30 %	N/A	N/A
Expected term (in years)	6	N/A	N/A
Risk-free rate	4.43 %	N/A	N/A
Weighted-average grant-date fair value	$ 9.50	N/A	N/A

In January 2026, the Company issued 1,487,317 options to purchase shares of the Company's common stock to eligible employees under the Omnibus Plans, at an average fair value of $9.75 per share. The total compensation cost of $15 million is estimated to be recognized over a three-year vesting period of these options.

Restricted Stock Units and Restricted Stock Phantom Units

The Company has restricted stock unit and restricted stock phantom unit plans for eligible employees, including officers. The value of the stock-settled restricted stock unit awards is established by the market price on the date of grant and is recorded as compensation expense ratably over the vesting terms. The restricted stock phantom unit awards represent a hypothetical interest in the Company's common stock, and, once vested, are settled in cash. Compensation expense related to the cash-settled awards is recorded as a liability and remeasured at the end of each reporting period over the applicable vesting term.

For the years ended December 31, 2025, 2024, and 2023, compensation costs charged to expense for the restricted stock units and restricted stock phantom units were $46 million, $53 million, and $73 million, respectively. For the years ended December 31, 2025, 2024, and 2023, capitalized compensation costs for the restricted stock units and restricted stock phantom units were $10 million, $9 million, and $11 million, respectively.

The following table summarizes stock-settled restricted stock unit activity for the years ended December 31, 2025, 2024, and 2023:

	2025		2024		2023	
	Units	Weighted Average Grant-Date Fair Value	Units	Weighted Average Grant-Date Fair Value	Units	Weighted Average Grant-Date Fair Value
	(In thousands, except per share amounts)					
Non-vested, beginning of year	1,415	$ 35.07	1,480	$ 30.69	1,885	$ 23.08
Granted	827	23.29	897	33.48	661	41.60
Assumed awards from Callon acquisition	—	—	1,498	35.43	—	—
Vested[3]	(797)	32.74	(2,295)	31.83	(975)	23.31
Forfeited	(282)	31.40	(165)	35.48	(69)	32.44
Expired	—	—	—	—	(22)	27.81
Non-vested, end of year[1][2]	1,163	29.19	1,415	35.07	1,480	30.69

(1) As of December 31, 2025, there was $10 million of total unrecognized compensation cost related to 1,163,194 unvested stock-settled restricted stock units.

(2) As of December 31, 2025, the weighted-average remaining life of unvested stock-settled restricted stock units is approximately 0.8 years.

(3) The grant date fair values of the stock-settled awards vested during 2025, 2024, and 2023 were $26 million, $73 million, and $23 million, respectively.

The following table summarizes cash-settled restricted stock phantom unit activity for the years ended December 31, 2025, 2024, and 2023:

	For the Year Ended December 31,		
	2025	2024	2023
		(In thousands)	
Non-vested, beginning of year	3,917	4,478	5,709
Granted[1]	2,302	2,369	1,972
Vested	(1,887)	(2,568)	(2,851)
Forfeited	(914)	(362)	(340)
Expired	—	—	(12)
Non-vested, end of year[2]	3,418	3,917	4,478

(1) Restricted stock phantom units granted during 2025, 2024, and 2023 included 2,301,540, 2,369,605, and 1,972,116 awards, respectively, based on the per-share market price of APA common stock.

(2) The outstanding liability for the unvested cash-settled restricted stock phantom units that had not been recognized as of December 31, 2025 was approximately $38 million.

In January 2026, the Company awarded 624,467 restricted stock units and 2,115,116 restricted stock phantom units based on APA's weighted-average per-share market price of $23.88 under the 2016 Plan to eligible employees. Total compensation cost for the restricted stock units and the restricted stock phantom units, absent any forfeitures, is estimated to be $15 million and $51 million, respectively, and was calculated based on the per-share fair market value of a share of the Company's common stock as of the grant date. Compensation cost will be recognized over a three-year vesting period for both plans. The restricted stock phantom units will be classified as a liability and remeasured at the end of each reporting period based on the change in fair value of one share of the Company's common stock, a Level 1 fair value measurement.

Performance Program

To provide long-term incentives for the Company's employees to deliver competitive shareholder returns, the Company makes annual grants of cash-settled conditional restricted stock phantom units to eligible employees. APA has a performance program for certain eligible employees with payout for a portion of the shares based upon measurement of total shareholder return (TSR) of APA common stock as compared to a designated peer group during a three-year performance period. Payout for the remaining portion of the shares is based on performance and financial objectives as defined in the plan. The overall results of the objectives are calculated at the end of the award's stated performance period and, if a payout is warranted, applied to the target number of restricted stock units awarded. The performance shares will immediately vest 50 percent at the end of the three-year performance period, with the remaining 50 percent vesting at the end of the following year. Grants from the performance programs outstanding at December 31, 2025, are as described below:

- In January 2022, the Company's Board of Directors approved the 2022 Performance Program, pursuant to the 2016 Plan. Eligible employees received the initial cash-settled conditional phantom units totaling 1,093,034 units. A total of 713,514 phantom units were outstanding as of December 31, 2025. The results for the performance period yielded a payout of 118 percent of target.
- In January 2023, the Company's Board of Directors approved the 2023 Performance Program, pursuant to the 2016 Plan. Eligible employees received the initial cash-settled conditional phantom units totaling 822,200 units. The actual number of phantom units awarded will be between zero and 200 percent of target. A total of 636,488 phantom units were outstanding as of December 31, 2025. The results for the performance period yielded a payout of 120 percent of target.
- In January 2024, the Company's Board of Directors approved the 2024 Performance Program, pursuant to the 2016 Plan. Eligible employees received the initial cash-settled conditional phantom units totaling 645,318 units. The actual number of phantom units awarded will be between zero and 200 percent of target. A total of 468,708 phantom units were outstanding as of December 31, 2025, from which a minimum of zero to a maximum of 937,416 units could be awarded. Eligible employees also received cash incentives as part of the 2024 Performance Program, which totaled $11 million as of December 31, 2025. The ultimate payout will range from zero to $22 million at the end of a three-year performance period.

- In January 2025, the Company's Board of Directors approved the 2025 Performance Program, pursuant to the 2016 Plan. Eligible employees received the initial cash-settled conditional phantom units totaling 1,028,112 units. The actual number of phantom units awarded will be between zero and 200 percent of target. A total of 871,793 phantom units were outstanding as of December 31, 2025, from which a minimum of zero to a maximum of 1,743,586 units could be awarded. Eligible employees also received cash incentives as part of the 2025 Performance Program, which totaled $14 million as of December 31, 2025. The ultimate payout will range from zero to $28 million at the end of a three-year performance period.

Compensation costs related to the conditional cash-settled awards are recorded as a liability and remeasured at the end of each reporting period over the applicable vesting term. Compensation costs charged to expense under the cash-settled performance programs were expenses of $45 million and $2 million during 2025 and 2023, respectively and a net benefit of $13 million during 2024. Capitalized compensation costs under the cash-settled performance programs were expenses of approximately $3 million and $100 thousand during 2025 and 2023, respectively and a net benefit of approximately $1 million during 2024.

The following table summarizes cash-settled conditional restricted stock phantom unit activity for the years ended December 31, 2025, 2024, and 2023:

	For the Year Ended December 31,		
	2025	2024	2023
	(In thousands)		
Non-vested, beginning of year	3,972	4,629	4,835
Granted	1,605	834	1,536
Assumed awards from Callon acquisition	—	2,934	—
Vested	(2,066)	(4,222)	(1,593)
Forfeited	(353)	(203)	(99)
Expired	(242)	—	(50)
Non-vested, end of year[(1)]	2,916	3,972	4,629

(1) As of December 31, 2025, the outstanding liability for the unvested cash-settled conditional restricted stock phantom units that had not been recognized was approximately $14 million.

In January 2026, the Company's Board of Directors approved the 2026 Performance Program, pursuant to the 2016 Plan. A portion of the award is based upon measurement of TSR similar to prior year awards, and the remaining portion of the award is based on performance and financial objectives as defined in the 2026 Performance Program. Eligible employees received conditional phantom units and cash incentives. The conditional phantom units totaled 904,442 units, with the ultimate units to be awarded ranging from zero to a maximum of 1,808,884 units. These phantom units represent a hypothetical interest in the Company's common stock, and, once vested, are settled in cash. These phantom units will be classified as a liability and remeasured at the end of each reporting period based on the change in fair value of one share of the Company's common stock, a Level 1 fair value measurement. The cash incentives totaled $14 million, with the ultimate payout ranging from zero to $28 million. Final payout of the awards will be determined at the end of a three-year performance period.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

Components of accumulated other comprehensive income include the following:

	As of December 31,		
	2025	2024	2023
	(In millions)		
Pension and postretirement benefit plan (Note 11)	$ 10	$ 12	$ 15
Accumulated other comprehensive income	$ 10	$ 12	$ 15

14. MAJOR CUSTOMERS

The Company is exposed to credit risk in the event of nonpayment by counterparties, a significant portion of which are concentrated in energy-related industries. The creditworthiness of customers and other counterparties is subject to continuing review, including the use of master netting agreements, where appropriate. During 2025, sales to EGPC in Egypt accounted for approximately 15 percent of the Company's worldwide crude oil, natural gas, and NGLs revenues. During 2024 and 2023, sales to EGPC accounted for approximately 17 percent and 15 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs revenues.

Management does not believe that the loss of any single customer would have a material adverse effect on the results of operations.

15. BUSINESS SEGMENT INFORMATION

As of December 31, 2025, the Company's consolidated subsidiaries are engaged in exploration, development and/or production activities across four operating segments: Egypt, North Sea, Suriname, and the U.S. The Company's business explores for, develops, and produces crude oil, natural gas, and natural gas liquids. The Company also has exploration interests in Uruguay, Alaska, and other international locations that may, over time, result in reportable discoveries and development opportunities.

The Chief Operating Decision Maker (CODM) is a function (not necessarily an individual) that allocates the resources of the reporting entity and assesses the performance of its segments. Decisions to assess performance and allocate resources are made by the Company's Chief Executive Officer (CEO), Mr. John J. Christmann, IV. Therefore, management has concluded that the CEO of the Company is the CODM. The information regularly reviewed by the CODM to assess performance and allocate resources is primarily associated with operating income from each segment and the resulting free cash flow, amongst other metrics. The Company concluded that the most comparable measure under U.S. GAAP is operating income.

Financial information for each segment is presented below:

	U.S.	Egypt[1]	North Sea	Intersegment Eliminations & Other[6]	Total[2]
			(In millions)		
2025					
Oil revenues	$ 3,010	$ 2,177	$ 622	$ —	$ 5,809
Natural gas revenues	193	460	117	—	770
Natural gas liquids revenues	616	—	34	—	650
Oil, natural gas, and natural gas liquids production revenues	3,819	2,637	773	—	7,229
Purchased oil and gas sales	1,691	—	—	—	1,691
Realized gains on commodity derivative instruments	31	—	—	—	31
	5,541	2,637	773	—	8,951
Operating Expenses:					
Lease operating expenses[5]	724	447	333	—	1,504
Gathering, processing, and transmission[5]	346	24	54	—	424
Purchased oil and gas costs[5]	1,070	—	—	—	1,070
Taxes other than income[5]	229	—	—	—	229
Exploration[4]	9	101	1	20	131
Depreciation, depletion, and amortization[5]	1,434	630	240	—	2,304
Asset retirement obligation accretion	41	—	117	—	158
Impairments	18	19	7	—	44
	3,871	1,221	752	20	5,864
Operating Income (Loss)	$ 1,670	$ 1,416	$ 21	$ (20)	3,087
Other Income (Expense):					
Gain on divestitures, net					301
Gains on previously sold Gulf of America properties					60
Realized losses on contingent consideration arrangements					(7)
Unrealized losses on commodity derivative instruments					(77)
Other					(8)
General and administrative					(350)
Transaction, reorganization, and separation					(102)
Financing costs, net					(113)
Income Before Income Taxes					$ 2,791
Total Assets[3]	$ 12,568	$ 3,055	$ 1,216	$ 922	$ 17,761
Net Property and Equipment	$ 9,019	$ 2,306	$ 570	$ 853	$ 12,748
Additions to Net Property and Equipment	$ 1,614	$ 747	$ 13	$ 299	$ 2,673

	U.S.	Egypt[1]	North Sea	Intersegment Eliminations & Other[6]	Total[2]
			(In millions)		
2024					
Oil revenues	$ 3,572	$ 2,620	$ 774	$ —	$ 6,966
Natural gas revenues	126	313	145	—	584
Natural gas liquids revenues	617	—	29	—	646
Oil, natural gas, and natural gas liquids production revenues	4,315	2,933	948	—	8,196
Purchased oil and gas sales	1,541	—	—	—	1,541
Realized gains on commodity derivative instruments	2	—	—	—	2
	5,858	2,933	948	—	9,739
Operating Expenses:					
Lease operating expenses[5]	820	464	406	—	1,690
Gathering, processing, and transmission[5]	354	25	53	—	432
Purchased oil and gas costs[5]	1,047	—	—	—	1,047
Taxes other than income[5]	270	—	—	—	270
Exploration[4]	134	112	1	66	313
Depreciation, depletion, and amortization[5]	1,340	625	301	—	2,266
Asset retirement obligation accretion	42	—	106	—	148
Impairments	320	—	809	—	1,129
	4,327	1,226	1,676	66	7,295
Operating Income (Loss)	$ 1,531	$ 1,707	$ (728)	$ (66)	2,444
Other Income (Expense):					
Gain on divestitures, net					289
Losses on previously sold Gulf of America properties					(273)
Realized losses on contingent consideration arrangements					(4)
Unrealized losses on commodity derivative instruments					(8)
Other					(6)
General and administrative					(372)
Transaction, reorganization, and separation					(168)
Financing costs, net					(367)
Income Before Income Taxes					$ 1,535
Total Assets[3]	$ 13,870	$ 3,606	$ 1,324	$ 590	$ 19,390
Net Property and Equipment	$ 9,109	$ 2,271	$ 712	$ 554	$ 12,646
Additions to Net Property and Equipment	$ 6,609	$ 765	$ 41	$ 84	$ 7,499

	U.S.	Egypt[1]	North Sea	Intersegment Eliminations & Other[6]	Total[2]
			(In millions)		
2023					
Oil revenues	$ 2,241	$ 2,683	$ 1,073	$ —	$ 5,997
Natural gas revenues	297	346	237	—	880
Natural gas liquids revenues	480	—	28	—	508
Oil, natural gas, and natural gas liquids production revenues	3,018	3,029	1,338	—	7,385
Purchased oil and gas sales	894	—	—	—	894
Realized gains on commodity derivative instruments	48	—	—	—	48
	3,960	3,029	1,338	—	8,327
Operating Expenses:					
Lease operating expenses[5]	593	474	369	—	1,436
Gathering, processing, and transmission[5]	249	33	52	—	334
Purchased oil and gas costs[5]	742	—	—	—	742
Taxes other than income[5]	207	—	—	—	207
Exploration[4]	14	119	19	43	195
Depreciation, depletion, and amortization[5]	745	524	271	—	1,540
Asset retirement obligation accretion	40	—	76	—	116
Impairments	11	—	50	—	61
	2,601	1,150	837	43	4,631
Operating Income (Loss)	$ 1,359	$ 1,879	$ 501	$ (43)	3,696
Other Income (Expense):					
Gain on divestitures, net					8
Losses on previously sold Gulf of America properties					(212)
Unrealized gains on commodity derivative instruments					51
Other					18
General and administrative					(351)
Transaction, reorganization, and separation					(15)
Financing costs, net					(312)
Income Before Income Taxes					$ 2,883
Total Assets[3]	$ 9,221	$ 3,503	$ 1,970	$ 550	$ 15,244
Net Property and Equipment	$ 5,689	$ 2,209	$ 1,628	$ 512	$ 10,038
Additions to Net Property and Equipment	$ 1,255	$ 834	$ 131	$ 93	$ 2,313

(1) Includes oil and gas production revenue that will be paid as taxes by EGPC on behalf of the Company for the years ended December 31, 2025, 2024, and 2023 of:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Oil	$ 536	$ 686	$ 729
Natural gas	114	83	95

(2) Includes a noncontrolling interest in Egypt for all periods presented.

(3) Intercompany balances are excluded from total assets.

(4) Exploration expense under Intersegment Eliminations & Other primarily reflects the Company's Suriname exploration activities.

(5) Represents significant segment expense categories that align with the segment-level information that is regularly provided to the CODM. The remaining expenses that comprise the Other Income (Loss) amount by segment are deemed to be other segment expense categories necessary to arrive at the segment profit or loss.

(6) Includes Suriname operating expenses as the operating segment has not met the quantitative thresholds to be separately reported.

16. SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

Oil and Gas Operations

The following table sets forth revenue and direct cost information relating to the Company's oil and gas exploration and production activities. The Company has no long-term agreements to purchase oil or gas production from foreign governments or authorities.

	United States	Egypt[1]	North Sea	Other International	Total[1]
			(In millions, except per boe)		
2025					
Oil and gas production revenues	$ 3,819	$ 2,637	$ 773	$ —	$ 7,229
Operating cost:					
Depreciation, depletion, and amortization[2]	1,411	625	239	—	2,275
Asset retirement obligation accretion	41	—	117	—	158
Lease operating expenses	724	447	333	—	1,504
Gathering, processing, and transmission	346	24	54	—	424
Exploration expenses	9	101	1	20	131
Impairments related to oil and gas properties	—	18	—	—	18
Production taxes[3]	227	—	—	—	227
Income tax	234	640	23	—	897
	2,992	1,855	767	20	5,634
Results of operations	$ 827	$ 782	$ 6	$ (20)	$ 1,595
2024					
Oil and gas production revenues	$ 4,315	$ 2,933	$ 948	$ —	$ 8,196
Operating cost:					
Depreciation, depletion, and amortization[2]	1,314	621	300	—	2,235
Asset retirement obligation accretion	42	—	106	—	148
Lease operating expenses	820	464	406	—	1,690
Gathering, processing, and transmission	354	25	53	—	432
Exploration expenses	134	112	1	66	313
Impairments related to oil and gas properties	315	—	796	—	1,111
Production taxes[3]	268	—	—	—	268
Income tax	235	770	(536)	—	469
	3,482	1,992	1,126	66	6,666
Results of operations	$ 833	$ 941	$ (178)	$ (66)	$ 1,530
2023					
Oil and gas production revenues	$ 3,018	$ 3,029	$ 1,338	$ —	$ 7,385
Operating cost:					
Depreciation, depletion, and amortization[2]	709	521	270	—	1,500
Asset retirement obligation accretion	40	—	76	—	116
Lease operating expenses	593	474	369	—	1,436
Gathering, processing, and transmission	249	33	52	—	334
Exploration expenses	14	119	19	43	195
Production taxes[3]	204	—	—	—	204
Income tax	254	828	414	—	1,496
	2,063	1,975	1,200	43	5,281
Results of operations	$ 955	$ 1,054	$ 138	$ (43)	$ 2,104

(1) Includes a noncontrolling interest in Egypt.

(2) Reflects DD&A of capitalized costs of oil and gas properties and, therefore, does not agree with DD&A reflected on Note 16—Business Segment Information.

(3) Reflects only amounts directly related to oil and gas producing properties and, therefore, does not agree with taxes other than income reflected on Note 16—Business Segment Information.

Costs Incurred in Oil and Gas Property Acquisitions, Exploration, and Development Activities

	United States	Egypt[2]	North Sea	Other International	Total[2]
			(In millions)		
2025					
Acquisitions	$ 23	$ 10	$ —	$ —	$ 33
Exploration	76	244	1	31	352
Development	1,558	530	96	288	2,472
Costs incurred[1]	$ 1,657	$ 784	$ 97	$ 319	$ 2,857
[1] Includes capitalized interest and asset retirement costs:					
Capitalized interest	$ 6	$ —	$ —	$ 39	$ 45
Asset retirement costs	51	—	84	—	135
2024					
Acquisitions[3]	$ 4,561	$ 3	$ —	$ —	$ 4,564
Exploration	150	227	1	61	439
Development	2,067	559	186	47	2,859
Costs incurred[1]	$ 6,778	$ 789	$ 187	$ 108	$ 7,862
[1] Includes capitalized interest and asset retirement costs:					
Capitalized interest	$ 3	$ —	$ —	$ 26	$ 29
Asset retirement costs	171	—	145	—	316
2023					
Acquisitions	$ 21	$ 4	$ —	$ —	$ 25
Exploration	31	226	44	131	432
Development	1,148	646	468	—	2,262
Costs incurred[1]	$ 1,200	$ 876	$ 512	$ 131	$ 2,719
[1] Includes capitalized interest, asset retirement costs, and Egypt modernization impacts as follows:					
Capitalized interest	$ —	$ —	$ —	$ 24	$ 24
Asset retirement costs	(4)	—	375	—	371

[2] Includes a noncontrolling interest in Egypt.

[3] Includes acquisitions of unproved properties of $955 million for the U.S. related to the Callon acquisition.

Capitalized Costs

The following table sets forth the capitalized costs and associated accumulated depreciation, depletion, and amortization relating to the Company's oil and gas acquisition, exploration, and development activities:

	United States	Egypt[1]	North Sea	Other International	Total[1]
			(In millions)		
2025					
Proved properties	$ 19,690	$ 14,724	$ 9,757	$ 721	$ 44,892
Unproved properties	384	99	—	132	615
	20,074	14,823	9,757	853	45,507
Accumulated DD&A	(11,220)	(12,558)	(9,189)	—	(32,967)
	$ 8,854	$ 2,265	$ 568	$ 853	$ 12,540
2024					
Proved properties	$ 19,246	$ 14,458	$ 9,661	$ 434	$ 43,799
Unproved properties	711	67	—	121	899
	19,957	14,525	9,661	555	44,698
Accumulated DD&A	(11,053)	(12,299)	(8,952)	—	(32,304)
	$ 8,904	$ 2,226	$ 709	$ 555	$ 12,394

(1) Includes a noncontrolling interest in Egypt.

Oil and Gas Reserve Information

Proved oil and gas reserves are those quantities of natural gas, crude oil, condensate, and NGLs, 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. Estimated proved developed oil and gas reserves can be expected to be recovered through existing wells with existing equipment and operating methods. The Company reports all estimated proved reserves held under production-sharing arrangements utilizing the "economic interest" method, which excludes the host country's share of reserves.

Estimated reserves that can be produced economically through application of improved recovery techniques are included in the "proved" classification when successful testing by a pilot project or the operation of an active, improved recovery program using reliable technology establishes the reasonable certainty for the engineering analysis on which the project or program is based. Economically producible means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. Reasonable certainty means a high degree of confidence that the quantities will be recovered. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating its proved reserves, the Company uses several different traditional methods that can be classified in three general categories: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy with similar properties. The Company will, at times, utilize additional technical analysis such as computer reservoir models, petrophysical techniques, and proprietary 3-D seismic interpretation methods to provide additional support for more complex reservoirs. Information from this additional analysis is combined with traditional methods outlined above to enhance the certainty of the Company's reserve estimates.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The reserve data in the following tables only represent estimates and should not be construed as being exact.

	Crude Oil and Condensate				
	United States	Egypt[1]	North Sea	Suriname	Total[1]
			(Thousands of barrels)		
Proved developed reserves:					
December 31, 2022	177,708	108,050	82,580	—	368,338
December 31, 2023	179,542	102,305	61,076	—	342,923
December 31, 2024	184,744	95,990	30,436	—	311,170
December 31, 2025	182,300	101,750	22,136	—	306,186
Proved undeveloped reserves:					
December 31, 2022	22,239	8,557	2,873	—	33,669
December 31, 2023	30,948	5,254	—	—	36,202
December 31, 2024	107,283	7,621	—	73,637	188,541
December 31, 2025	121,079	7,578	—	73,789	202,446
Total proved reserves:					
Balance December 31, 2022	199,947	116,607	85,453	—	402,007
Extensions, discoveries and other additions	43,613	12,979	301	—	56,893
Purchases of minerals in-place	20	—	—	—	20
Revisions of previous estimates	(3,520)	10,505	(12,002)	—	(5,017)
Production	(28,795)	(32,532)	(12,676)	—	(74,003)
Sales of minerals in-place	(775)	—	—	—	(775)
Balance December 31, 2023	210,490	107,559	61,076	—	379,125
Extensions, discoveries and other additions	100,778	18,115	—	73,637	192,530
Purchases of minerals in-place	124,112	—	—	—	124,112
Revisions of previous estimates	(9,642)	10,521	(21,000)	—	(20,121)
Production	(47,043)	(32,584)	(9,640)	—	(89,267)
Sales of minerals in-place	(86,668)	—	—	—	(86,668)
Balance December 31, 2024	292,027	103,611	30,436	73,637	499,711
Extensions, discoveries and other additions	39,804	17,646	—	—	57,450
Revisions of previous estimates	24,942	20,088	528	152	45,710
Production	(45,817)	(32,017)	(8,828)	—	(86,662)
Sales of minerals in-place	(7,577)	—	—	—	(7,577)
Balance December 31, 2025	303,379	109,328	22,136	73,789	508,632

(1) Includes proved reserves of 36 MMbbls, 35 MMbbls, 36 MMbbls, and 39 MMbbls as of December 31, 2025, 2024, 2023, and 2022, respectively, attributable to a noncontrolling interest in Egypt.

	Natural Gas Liquids		
	United States	North Sea	Total[1]
	(Thousands of barrels)		
Proved developed reserves:			
December 31, 2022	158,745	2,230	160,975
December 31, 2023	153,486	1,460	154,946
December 31, 2024	153,523	744	154,267
December 31, 2025	180,690	899	181,589
Proved undeveloped reserves:			
December 31, 2022	19,004	76	19,080
December 31, 2023	18,401	—	18,401
December 31, 2024	54,674	—	54,674
December 31, 2025	58,438	—	58,438
Total proved reserves:			
Balance December 31, 2022	177,749	2,306	180,055
Extensions, discoveries and other additions	25,711	371	26,082
Purchases of minerals in-place	21	—	21
Revisions of previous estimates	(8,568)	(764)	(9,332)
Production	(22,993)	(453)	(23,446)
Sales of minerals in-place	(33)	—	(33)
Balance December 31, 2023	171,887	1,460	173,347
Extensions, discoveries and other additions	62,988	—	62,988
Purchases of minerals in-place	51,406	—	51,406
Revisions of previous estimates	(20,167)	(277)	(20,444)
Production	(27,039)	(439)	(27,478)
Sales of minerals in-place	(30,878)	—	(30,878)
Balance December 31, 2024	208,197	744	208,941
Extensions, discoveries and other additions	16,232	—	16,232
Revisions of previous estimates	47,852	614	48,466
Production	(27,836)	(459)	(28,295)
Sales of minerals in-place	(5,317)	—	(5,317)
Balance December 31, 2025	239,128	899	240,027

	Natural Gas			
	United States	Egypt[1]	North Sea	Total[1]
	(Millions of cubic feet)			
Proved developed reserves:				
December 31, 2022	1,166,218	399,502	66,292	1,632,012
December 31, 2023	1,003,956	377,144	46,839	1,427,939
December 31, 2024	866,460	332,905	28,028	1,227,393
December 31, 2025	1,095,395	371,335	12,741	1,479,471
Proved undeveloped reserves:				
December 31, 2022	210,862	1,068	2,304	214,234
December 31, 2023	99,495	2,612	—	102,107
December 31, 2024	307,775	27,499	—	335,274
December 31, 2025	338,100	27,780	—	365,880
Total proved reserves:				
Balance December 31, 2022	1,377,080	400,570	68,596	1,846,246
Extensions, discoveries and other additions	158,118	14,188	3,335	175,641
Purchases of minerals in-place	136	—	—	136
Revisions of previous estimates	(266,664)	83,907	(6,739)	(189,496)
Production	(165,083)	(118,909)	(18,353)	(302,345)
Sales of minerals in-place	(136)	—	—	(136)
Balance December 31, 2023	1,103,451	379,756	46,839	1,530,046
Extensions, discoveries and other additions	354,267	60,366	—	414,633
Purchases of minerals in-place	279,615	—	—	279,615
Revisions of previous estimates	(224,118)	26,792	(4,176)	(201,502)
Production	(176,941)	(106,510)	(14,635)	(298,086)
Sales of minerals in-place	(162,039)	—	—	(162,039)
Balance December 31, 2024	1,174,235	360,404	28,028	1,562,667
Extensions, discoveries and other additions	95,264	65,514	—	160,778
Revisions of previous estimates	386,166	101,230	(3,856)	483,540
Production	(187,793)	(128,033)	(11,431)	(327,257)
Sales of minerals in-place	(34,377)	—	—	(34,377)
Balance December 31, 2025	1,433,495	399,115	12,741	1,845,351

(1) Includes proved reserves of 133 Bcf, 120 Bcf, 127 Bcf, and 134 Bcf as of December 31, 2025, 2024, 2023, and 2022, respectively, attributable to a noncontrolling interest in Egypt.

	Total Equivalent Reserves				
	United States	Egypt[1]	North Sea	Suriname	Total[1]
	(Thousands barrels of oil equivalent)				
Proved developed reserves:					
December 31, 2022	530,823	174,633	95,859	—	801,315
December 31, 2023	500,354	165,162	70,343	—	735,859
December 31, 2024	482,677	151,474	35,852	—	670,003
December 31, 2025	545,555	163,639	25,159	—	734,353
Proved undeveloped reserves:					
December 31, 2022	76,386	8,735	3,333	—	88,454
December 31, 2023	65,931	5,690	—	—	71,621
December 31, 2024	213,253	12,204	—	73,637	299,094
December 31, 2025	235,867	12,208	—	73,789	321,864
Total proved reserves:					
Balance December 31, 2022	607,209	183,368	99,192	—	889,769
Extensions, discoveries and other additions	95,677	15,344	1,228	—	112,249
Purchases of minerals in-place	64	—	—	—	64
Revisions of previous estimates	(56,532)	24,490	(13,889)	—	(45,931)
Production	(79,302)	(52,350)	(16,188)	—	(147,840)
Sales of minerals in-place	(831)	—	—	—	(831)
Balance December 31, 2023	566,285	170,852	70,343	—	807,480
Extensions, discoveries and other additions	222,811	28,176	—	73,637	324,624
Purchases of minerals in-place	222,121	—	—	—	222,121
Revisions of previous estimates	(67,162)	14,986	(21,973)	—	(74,149)
Production	(103,572)	(50,336)	(12,518)	—	(166,426)
Sales of minerals in-place	(144,553)	—	—	—	(144,553)
Balance December 31, 2024	695,930	163,678	35,852	73,637	969,097
Extensions, discoveries and other additions	71,913	28,565	—	—	100,478
Revisions of previous estimates	137,155	36,960	499	152	174,766
Production	(104,952)	(53,356)	(11,192)	—	(169,500)
Sales of minerals in-place	(18,624)	—	—	—	(18,624)
Balance December 31, 2025	781,422	175,847	25,159	73,789	1,056,217

(1) Includes total proved reserves of 59 MMboe, 55 MMboe, 57 MMboe, and 61 MMboe as of December 31, 2025, 2024, 2023, and 2022, respectively, attributable to a noncontrolling interest in Egypt.

During 2025, the Company added approximately 100 MMboe from extensions, discoveries, and other additions. The Company recorded 72 MMboe of exploration and development adds in the U.S., derived from drilling activity in the Permian Basin primarily focused on the Spraberry, Bone Spring, and Wolfcamp producing horizons. International operations contributed 28 MMboe of exploration and development additions occurring in Egypt primarily from gas-focused onshore exploration and appraisal.

The Company realized combined upward revision of previously estimated reserves of 175 MMboe. Upward revisions related to pricing and interest totaled 37 MMboe, driven primarily by an increase in Permian Basin gas pricing. Engineering and well performance adjustments totaled 138 MMboe in the U.S. and Egypt. Upward revisions of 100 MMboe in the U.S. is related to changes to development plans and updates due to reservoir performance. Egypt realized positive revisions of 38 MMboe from gas infrastructure optimization and improved recovery projects.

During 2024, the Company added approximately 325 MMboe from extensions, discoveries, and other additions. The Company recorded 223 MMboe of exploration and development adds in the U.S., derived from drilling activity in the Permian Basin targeting the Wolfcamp, Bone Spring and Spraberry producing horizons. International operations contributed 102 MMboe of exploration and development adds, with Egypt contributing 28 MMboe from onshore exploration and appraisal and 74 MMboe from the Suriname final investment decision.

During 2023, the Company added approximately 112 MMboe from extensions, discoveries, and other additions. The Company recorded 96 MMboe of exploration and development adds in the U.S., comprising 67 MMboe in the Permian Basin, 27 MMboe in the Delaware Basin, and 2 MMboe in the Texas Gulf Coast. Drilling programs for the Permian and Delaware Basins include the Wolfcamp, Bone Spring and Spraberry with the Austin Chalk as the primary focus for the Texas Gulf Coast. International operations contributed 16 MMboe of exploration and development adds, with Egypt contributing 15 MMboe from onshore exploration and appraisal activity primarily in the Khalda Area and 1 MMboe from the North Sea. The Company had combined downward revisions of previously estimated reserves of 46 MMboe, primarily driven by revisions in the U.S. Downward revisions for price and interest changes accounted for 83 MMboe, partially offset by engineering and performance upward revisions of 37 MMboe.

Approximately 8 percent of the Company's year-end 2025 estimated proved developed reserves are classified as proved not producing. These reserves relate to zones that are either behind pipe, or that have been completed but not yet produced, or zones that have been produced in the past, but are not now producing because of mechanical reasons. These reserves are considered to be a lower tier of reserves than producing reserves because they are frequently based on volumetric calculations rather than performance data. Future production associated with behind pipe reserves is scheduled to follow depletion of the currently producing zones in the same wellbores. Additional capital may have to be spent to access these reserves. The capital and economic impact of production timing are reflected in this Note 16, under "Future Net Cash Flows."

Future Net Cash Flows

Future cash inflows as of December 31, 2025, 2024, and 2023 were calculated using an unweighted arithmetic average of oil and gas prices in effect on the first day of each month in the respective year, except where prices are defined by contractual arrangements. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Future development costs include abandonment and dismantlement costs.

The following table sets forth unaudited information concerning future net cash flows for proved oil and gas reserves, net of income tax expense. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under laws in effect as of December 31, 2025, and which relate to oil and gas producing activities. This information does not purport to present the fair market value of the Company's oil and gas assets, but does present a standardized disclosure concerning possible future net cash flows that would result under the assumptions used.

	United States	Egypt[1]	North Sea	Suriname	Total[1]
			(In millions)		
2025					
Cash inflows	$ 25,957	$ 9,208	$ 1,769	$ 5,033	$ 41,967
Production costs	(9,192)	(1,978)	(1,077)	(1,294)	(13,541)
Development costs	(3,640)	(1,477)	(2,756)	(1,658)	(9,531)
Income tax expense	(587)	(1,686)	565	(578)	(2,286)
Net cash flows	12,538	4,067	(1,499)	1,503	16,609
10 percent discount rate	(4,563)	(971)	630	(867)	(5,771)
Discounted future net cash flows[2]	$ 7,975	$ 3,096	$ (869)	$ 636	$ 10,838
2024					
Cash inflows	$ 27,534	$ 9,342	$ 2,828	$ 5,881	$ 45,585
Production costs	(9,665)	(1,716)	(1,399)	(1,436)	(14,216)
Development costs	(4,124)	(1,517)	(2,538)	(1,096)	(9,275)
Income tax expense	(921)	(1,923)	85	(822)	(3,581)
Net cash flows	12,824	4,186	(1,024)	2,527	18,513
10 percent discount rate	(4,317)	(872)	535	(2,280)	(6,934)
Discounted future net cash flows[2]	$ 8,507	$ 3,314	$ (489)	$ 247	$ 11,579
2023					
Cash inflows	$ 21,417	$ 9,921	$ 5,761	$ —	$ 37,099
Production costs	(8,328)	(1,690)	(2,773)	—	(12,791)
Development costs	(2,238)	(1,235)	(2,461)	—	(5,934)
Income tax expense	(949)	(2,222)	(946)	—	(4,117)
Net cash flows	9,902	4,774	(419)	—	14,257
10 percent discount rate	(3,749)	(943)	476	—	(4,216)
Discounted future net cash flows[2]	$ 6,153	$ 3,831	$ 57	$ —	$ 10,041

(1) Includes discounted future net cash flows of approximately $1.0 billion, $1.1 billion, and $1.3 billion as of December 31, 2025, 2024, and 2023, respectively, attributable to a noncontrolling interest in Egypt.

(2) Estimated future net cash flows before income tax expense, discounted at 10 percent per annum, totaled approximately $12.6 billion, $14.4 billion, and $13.6 billion as of December 31, 2025, 2024, and 2023, respectively.

The following table sets forth the principal sources of change in the discounted future net cash flows:

	For the Year Ended December 31,		
	2025	2024	2023
		(In millions)	
Sales, net of production costs	$ (5,073)	$ (5,806)	$ (5,408)
Net change in prices and production costs	(2,859)	269	(7,089)
Discoveries and improved recovery, net of related costs	762	3,557	1,869
Change in future development costs	(993)	(695)	(413)
Previously estimated development costs incurred during the period	1,592	793	825
Revision of quantities	3,718	(428)	(262)
Purchases of minerals in-place	—	4,166	1
Accretion of discount	1,438	1,357	2,260
Change in income taxes	999	737	1,467
Sales of minerals in-place	(312)	(1,865)	(18)
Change in production rates and other	(13)	(547)	(793)
	$ (741)	$ 1,538	$ (7,561)

SCHEDULE A

APA Corporation
2026 Performance Share Program Agreement

GRANT NOTICE

Participant Name: [Name]

Company: APA Corporation

Notice: A summary of the terms of your Conditional Grants of Restricted Stock Units ("**RSUs**") and a Cash-Based Award for a formulaic amount and treated as a Performance Award ("**Cash Award**") under the 2026 Performance Share Program is set out in this notice (the "**Grant Notice**") but subject always to the terms of the APA Corporation 2016 Omnibus Compensation Plan, as amended (the "**Plan**") and the 2026 Performance Share Program Agreement (the "**Agreement**"). In the event of any inconsistency between the terms of this Grant Notice and the terms of the Plan and the Agreement, the terms of the Plan and the Agreement shall prevail. The Conditional Grants are both Cash-Based Awards under Section 10 of the Plan and are subject to the provisions of the Plan governing Performance Awards.

You have been granted Conditional Grants of RSUs and the Cash Award in accordance with the terms of the Plan and the Agreement.

Details of the RSUs and the Cash Award that you are conditionally entitled to receive are provided to you in this Grant Notice and maintained on your account at netbenefits.fidelity.com.

Type of Award: Conditional grants of RSUs (for the TSR performance measure) and the Cash Award (for the CROIC performance measure) based on a target percentage of annual base salary determined at the beginning of the Performance Period derived from job level (each, a "**Conditional Grant**").

Restricted Stock Unit: A Restricted Stock Unit as defined in the Plan and meaning the right granted to you of the Conditional Grant, as adjusted at the end of the Performance Period, to receive one share of Stock or the cash equivalent thereof for each RSU at the end of the specified Vesting Period.

Cash Award: A Cash-Based Award as defined in the Plan and meaning the right granted to you of the Conditional Grant, as adjusted at the end of the Performance Period, to receive a formulaic amount of cash at the end of the specified Vesting Period.

Stock: The $0.625 par value common stock of the Company or as otherwise defined in the Plan.

Grant: Conditional Grants related to [NUMBER] Restricted Stock Units ("**Target RSUs**") and the $[AMOUNT] Cash Award ("**Target Cash Award**").

Grant Date: [Date]

Conditions: Subject always to the terms of the Plan and the Agreement, the Conditional Grants of RSUs and the Cash Award shall be made as of the Grant Date. At the end of the Performance Period, the Committee shall derive and confirm the number of Conditional Grant RSUs that will actually be awarded as RSUs and the dollar amount of the Conditional Grant Cash Award that will actually be awarded in cash to you based upon measurement of the specific performance goals, applicable performance percentage levels, and applicable weighting percentages during the Performance Period as set forth in Schedule B to the Agreement, provided that you remain an Eligible Person and employed by the Company or its Affiliate as of the final day of the Performance Period. Once granted at the conclusion of the Performance Period, such RSUs and the Cash Award shall remain subject to a vesting schedule (as set forth below) (the "**Vesting Period**"). Once vested, you shall be paid the value of your RSUs in cash and the cash amount of the Cash Award (in each case, net of cash withheld for applicable tax withholdings) if you remain employed as an Eligible Person during the Vesting Period including the vesting date.

Performance Measure: The performance measures for the Conditional Grants, the performance percentage levels, and the applicable weighting percentages to be applied over the Performance Period are set forth on Schedule B to the Agreement.

At the end of the Performance Period, the Committee shall determine and certify the attainment of each performance goal based on the established performance percentage levels and apply the applicable weighting percentages to determine the Final RSU Amount and the Final Cash Award Amount to be awarded to you.

Performance Period: The three-year period commencing January 1, 2026, and ending December 31, 2028.

Vesting Period: Any RSUs and Cash Award awarded shall vest in accordance with the following schedule (the "**Vesting Period**"), if you remain employed as an Eligible Person as of such vesting date:

Vesting Date	Percentage Vested
First trading day following the close of the Performance Period	50%
First trading day on or after the anniversary of the first trading day following the close of the Performance Period	Additional 50%

Upon such vesting (except as provided for below), the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to you within sixty (60) days of such vesting date.

Ceasing Employment: ***Generally***. Except upon a Change of Control, death, Disability, or Retirement (each as described below), cessation of employment (i) during the Performance Period shall result in the immediate forfeiture of the entire amount of the Conditional Grants or (ii) after completion of the Performance Period shall result in the immediate forfeiture of all unvested RSUs and the Cash Award.

Retirement. If, after the first three (3) months of the Performance Period (and not before), your termination of employment from the Company and the Affiliates occurs by reason of your Retirement, you shall be deemed to continue to be

employed as an Eligible Person for purposes of this Conditional Grant and shall continue to vest with respect to a specified percentage of RSUs and the Cash Award over the Vesting Period, if you meet the Retirement conditions set forth in section 6 of the Agreement. In the event of a Change of Control after you retire during the period commencing on the first day following the first three (3) months of the Performance Period and ending on the last day of the Vesting Period, vesting is accelerated to 100% for you upon the occurrence of the Change of Control. In the event of a Change of Control prior to your termination of employment by reason of Retirement and after the first three (3) months of the Performance Period and ending on the last day of the Vesting Period, you shall become 100% vested upon your termination of employment by reason of Retirement. Unless expressly otherwise provided in the Agreement with respect to Retirement and Change of Control, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to you upon the earlier to occur of a 409A Change of Control or the normal vesting dates (in the applicable percentage amounts). Payment shall be made within thirty (30) days of a 409A Change of Control or within sixty (60) days of the normal vesting dates, whichever is applicable.

Death or Disability. Vesting is accelerated to 100% upon your death or cessation of employment by reason of Disability during the Performance Period or the subsequent Vesting Period (or, only in the case of death, while treated as an Eligible Person following Retirement, as described above). Upon your death or cessation of employment by reason of Disability during the Performance Period, the Target RSUs and Target Cash Award shall vest. Upon such vesting, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to your designated beneficiary, legal representatives, heirs, or legatees, as applicable, in accordance with the terms of the Plan and the Agreement. You can name a beneficiary on a form approved by the Committee.

Change of Control. Vesting is accelerated to 100% upon your Involuntary Termination or Voluntary Termination with Cause occurring (i) on or after a Change of Control that occurs on or before the end of the Performance Period, if you are an Eligible Person at the time of such termination, with vesting of the Target RSUs and the Target Cash Award, or (ii) on or after a Change of Control that occurs after completion of the Performance Period. Upon such vesting, the applicable amount of cash, subject to required tax withholding, shall be paid by the Company to you within thirty (30) days of such vesting date.

Withholding: The Company and you will comply with all federal and state laws and regulations respecting the required withholding, deposit, and payment of any income, employment, or other taxes relating to the Conditional Grants.

Clawback: These Conditional Grants are subject to the Company's Executive Compensation Clawback Policy (a copy of which is provided with this Notice) and the recoupment and reimbursement policies as provided in the Agreement.

Dividends on RSUs: The Company will credit each of your Conditional Grant RSUs and RSUs, as applicable, with Dividend Equivalents. For purposes of this Conditional Grant, a Dividend Equivalent is an amount equal to the cash dividend payable per share of Stock multiplied by the number of shares of Stock then underlying such outstanding Conditional Grant RSUs or RSUs, as applicable. Such amount will be credited to a book entry account on your behalf at the time the Company pays any

cash dividend on its Stock. Your rights in any such Dividend Equivalents will vest at the same time as, and only to the extent that, the underlying Conditional Grant RSUs or RSUs, as applicable, vest and will be distributed at the same time in cash (subject to applicable withholdings), and only to the extent, as the related RSUs are to be distributed to you as provided in the Agreement and to which such Dividend Equivalents apply. Dividend Equivalents on Conditional Grant RSUs will accrue and be credited by the Company but will be subject to the same performance goals, applicable performance percentage levels and applicable weighting percentages as the related Conditional Grant RSUs. Dividend Equivalents (as so adjusted) will not be paid to you until you become vested in the related RSUs granted at the end of the Performance Period and will be forfeited in the event of the forfeiture and cancellation of the related Conditional Grant RSUs and RSUs pursuant to the Agreement.

Acceptance: Please complete the online grant acceptance as promptly as possible to accept or reject your Conditional Grants. You can access this through your account at netbenefits.fidelity.com. By accepting your Conditional Grants, you will have agreed to the terms and conditions set forth in the Agreement, including, but not limited to, the non-compete and non-disparagement provisions set forth in sections 6 and 7 of the Agreement, and the terms and conditions of the Plan. If you do not accept your grant, your Conditional Grants and the related RSUs and the Cash Award will not vest and you will be unable to receive your Conditional Grants or the related RSUs and the Cash Award.

SCHEDULE B

APA Corporation
2026 Performance Share Program Agreement

PERFORMANCE MEASURES

Performance Goals: ***1. Total Shareholder Return***

At the end of the Performance Period, the Committee shall derive and confirm a portion of the number of Conditional Grant RSUs that will actually be awarded as RSUs to you based upon the measurement of total shareholder return ("**TSR**") of the Stock as compared to a designated Peer Group during the Performance Period, if you remain an Eligible Person and employed by the Company or its Affiliate as of the final day of the Performance Period.

TSR is determined by dividing (i) the sum of the cumulative amount of a company's or index fund's dividends for the performance period (assuming same-day reinvestment into the company's common stock or index fund on the ex-dividend date) and the share price of the company or index fund at the end of the performance period minus the share price at the beginning of the performance period by (ii) the share price at the beginning of the performance period.

- **Begin Price:** Average per share closing price of a share or share equivalent on the applicable stock exchange for the three calendar months immediately preceding the beginning of the performance period.
- **End Price:** Average per share closing price of a share or share equivalent on the applicable stock exchange for the last three calendar months of the performance period.
- **Dividends:** Includes dividends paid throughout the performance period.
- **Designated Peer Group:**
    - Antero Resources Corporation
    - Chevron Corporation
    - Chord Energy Corporation
    - Civitas Resources, Inc.
    - ConocoPhillips Company
    - Coterra Energy Inc.
    - Devon Energy Corporation
    - Diamondback Energy, Inc.
    - EOG Resources, Inc.
    - EQT Corporation
    - Expand Energy Corporation
    - Exxon Mobil Corporation
    - Magnolia Oil & Gas Corporation
    - Matador Resources Company
    - Murphy Oil Corporation
    - Occidental Petroleum Corporation
    - Ovintiv Inc.
    - Permian Resources Corporation

- Range Resources Corporation
- SM Energy Company
- S&P 500 Index

- S&P 500 Index

- APA's performance over the three-year performance period will be directly ranked within the peer group, resulting in the application of a single multiplier to the target shares to derive the number of shares awarded. The multiplier will range from 0.0 to 2.0 based on the ranking achieved in the table set forth in the Measurement section below.

- Should consolidation among peers in the marketplace occur, the ranking schedule would adjust to accommodate the reduced number of peers.

2. Business Performance

The Committee shall derive and confirm a portion of the Conditional Grant Cash Award that will be awarded as cash to you based upon a performance target determined at the beginning of the Performance Period related to the following criteria:

- Cash Return on Invested Capital ("**CROIC**")

Performance is measured based on the three-year average relative to target.

Weighting and Targets: The Committee will consider each of the above performance measures related to the Company as follows:

Metric	Weighting	Threshold	Target	Max
TSR	60%	20th	Between 11th and 12th	1st – 3rd
CROIC	40%	50%	100%	200%

Measurement: ***1. Total Shareholder Return***

At the conclusion of the three-year performance period, a calculation of TSR performance will be made and confirmed. The TSR portion of the total Target RSUs will be determined based upon the final TSR performance as follows:

Rank Against Peers	Payout Multiple
1	2.00
2	2.00
3	2.00
4	1.80
5	1.71
6	1.63
7	1.54
8	1.46

Rank Against Peers	Payout Multiple
9	1.37
10	1.29
11	1.15
12	0.95
13	0.86
14	0.76
15	0.67
16	0.57
17	0.48
18	0.39
19	0.29
20	0.20
21	0.00
22	0.00
23	0.00

If APA's absolute TSR for the three-year performance period is negative, the TSR portion of the total Target RSUs will be capped at the 1.00 Payout Multiple, regardless of whether the Rank Against Peers above achieved a higher Payout Multiple.

2. Business Performance

CROIC will be evaluated over the three-year Performance Period against a performance target determined prior to March 31 at the beginning of the performance period. Performance will be measured based on the three-year average relative to target. The payout of the Cash Award will be determined based upon the three-year average CROIC.

The three-year average performance for CROIC will be interpolated as follows to determine the final achievement percentage for each metric.

Threshold	Target	Max
50%	100%	200%

APA Corporation
2026 Performance Share Program Agreement

This 2026 Performance Share Program Agreement (this "**Agreement**"), dated as of the Grant Date set forth in the Grant Notice, is made between APA Corporation (together with its Affiliates, the "**Company**") and the Participant set forth in the Grant Notice. The Grant Notice is included in and made part of this Agreement.

In this Agreement and the Grant Notice, unless the context otherwise requires, words and expressions shall have the meanings given to them in the Plan except as herein defined.

Definitions

"**409A Change of Control**" means a Change of Control that constitutes, with respect to APA Corporation, a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation" within the meaning of Section 409A(a)(2)(A)(v) of the Internal Revenue Code of 1986, as amended (the "**Code**") and Treasury Regulations Section 1.409A-3(i)(5).

"**Base Salary**" means, with regard to any Participant, such Participant's annual base compensation as an employee of the Company determined immediately prior to the beginning of the Performance Period, without regard to any bonus, pension, profit sharing, stock option, life insurance or salary continuation plan which the Participant either receives or is otherwise entitled to have paid on his or her behalf.

"**Conditional Grant**" means the conditional entitlement, evidenced by this Agreement to receive all or a portion of the Target RSUs and the Target Cash Award and the Final RSU Amount and Final Cash Award Amount, subject to and in accordance with the provisions of this Agreement.

"**Disability**" or "**Disabled**" means the Participant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months. Participant agrees that a final and binding determination of "Disability" will be made by the Company's representative under the Company's group long-term disability plan or any successor thereto or, if there is no such representative and there is a dispute as to the determination of "Disability," it will be decided in a court of law in Harris County, Texas.

"**Fair Market Value**" means the fair market value of a share of the Stock as determined by the Committee by the reasonable application of such reasonable valuation method, consistently applied, as the Committee deems appropriate; *provided, however*, that if the Committee has not made such determination, such fair market value shall be the per share closing price of the Stock as reported on Nasdaq or on such other exchange or electronic trading system as, on the date in question, reports the largest number of traded shares of stock; *provided further, however*, that, if there are no Stock transactions on such date, the Fair Market Value shall be determined as of the immediately preceding date on which there were Stock transactions.

"**Final Amount**" means with regard to any Participant, the sum of (i) an amount of cash equal to the Fair Market Value of the shares of Stock underlying the Final RSU Amount and related Dividend Equivalents and (ii) the amount of cash equal to the Final Cash Award Amount.

"**Final Cash Award Amount**" means with regard to any Participant, the Target Cash Award, as specified in each Participant's Grant Notice, times the applicable multiple factor determined under the Performance Measures at the end of the Performance Period.

"**Final RSU Amount**" means with regard to any Participant, the number of Target RSUs, as specified in each Participant's Grant Notice, times the applicable multiple factor determined under the Performance Measures at the end of the Performance Period.

"**Grant Notice**" means the separate notice, attached as Schedule A hereto, along with Schedule B, given to the Participant specifying the Target RSUs and Target Cash Award and other applicable performance percentage levels, performance criteria, and applicable weighting percentages for that Participant.

"**Involuntary Termination**" means the termination of employment of the Participant by the Company or its successor or an applicable Affiliate for any reason on or after a Change of Control; *provided*, that the termination does not result from an act of the Participant that (a) constitutes common-law fraud, a felony, or a gross malfeasance of duty and (b) is materially detrimental to the best interests of the Company or its successor; *provided* that, notwithstanding anything else in this Agreement to the contrary, an Involuntary Termination shall not be deemed to occur solely because a Participant transfers employment from the Company to an Affiliate, from an Affiliate to the Company, or from one Affiliate to another Affiliate.

"**Participant**" means an Eligible Person who has been designated to receive one or more Conditional Grants in accordance with the Plan. For purposes of this Agreement, the group of Eligible Persons shall include all full-time and designated part-time employees of the Company who are employed as employees of the Company (as designated by the Company for payroll purposes), but excluding Egyptian nationals employed outside of the United States, employees categorized by the Company (for payroll purposes) as non-exempt support and field staff, leased employees, interns, or any employee of the Company who is covered under a collective bargaining agreement, unless such collective bargaining agreement specifically provides for coverage under the Plan.

"**Payout Amount**" means the vested portion of the Final Amount.

"**Peer Group**" means the group of companies or index funds selected by the Committee for purposes of this Agreement as set forth in the Grant Notice. Should consolidation among any Peer Group companies in the marketplace occur during the Performance Period, the Committee will determine the appropriate adjustments to accommodate the reduced number of Peer Group companies for the Performance Period. Should a Change of Control of APA Corporation occur during the Performance Period, the Committee will determine the appropriate adjustments to measure APA Corporation's TSR for the Performance Period. The Peer Group companies for any particular Performance Period shall be determined at the commencement of such Performance Period.

"**Performance Measures**" means, as set forth in the Grant Notice, (i) APA Corporation's TSR over the Performance Period compared to the TSR of the Company's Peer Group over the Performance Period and (ii) APA Corporation's achievement of pre-established performance goals over the Performance Period, as applicable. For purposes of determining TSR performance, at the end of the Performance Period, the Peer Group companies and the Company will be ranked together based on their TSR for the Performance Period from the highest TSR being number 1 to the lowest TSR being the number of Peer Group companies or index funds, including the Company, remaining in the group at the end of the Performance Period. Based on the Company's relative TSR rank amongst the Peer Group companies or index funds for the Performance Period, a Participant who remains employed as of the last day of the Performance Period will be issued RSUs at the close of the Performance Period as determined by the Company's percentile rank as set forth in the Grant Notice (the Final Amount). At the end of the Performance Period, the Committee shall also determine and certify the levels of other specific performance goals achieved and apply the applicable performance percentage levels and weighting percentages as set forth in the Grant Notice. Based on the Company's level of goal achievement, a Participant who remains employed as of the last day of the Performance Period will be issued RSUs and the Cash Award, as applicable, on the day following the close of the Performance Period as determined by the Committee as set forth in the Grant Notice (the Final Amount).

"**Performance Period**" means the three-year period as specified in the Grant Notice.

"**Plan**" means the APA Corporation 2016 Omnibus Compensation Plan, as amended.

"**Retirement**" means, with respect to a Participant and for purposes of this Agreement, the date the Participant terminates employment with the Company after attaining (i) age 55 and (ii) a certain combination of age and Years of Service set forth in the matrix in Exhibit A attached hereto.

"**Target Cash Award**" means, with regard to any Participant, such amount of the Cash Award as specified in each Participant's Grant Notice. The amount of such Target Cash Award shall be based upon a target percentage of annual Base Salary determined at the beginning of the Performance Period derived from job level.

"**Target RSUs**" means, with regard to any Participant, such number of RSUs as specified in each Participant's Grant Notice. The number of such Target RSUs shall be based upon a target percentage of annual Base Salary determined at the beginning of the Performance Period derived from job level.

"**Total Shareholder Return**" or "**TSR**" is determined by dividing (i) the sum of the cumulative amount of a company's dividends for the Performance Period (assuming same-day reinvestment into the company's common stock on the ex-dividend date) and the share price of the company at the end of the Performance Period minus the share price at the beginning of the Performance Period, by (ii) the share price at the beginning of the Performance Period. The share price at the beginning of the Performance Period is the average per share closing price of a share or share equivalent on the applicable stock exchange for the three calendar months immediately preceding the beginning of the Performance Period, and the share price at the end of the Performance Period is the average per share closing price of a share or share equivalent on the applicable stock exchange for the last three calendar months of the Performance Period.

"**Voluntary Termination with Cause**" occurs upon a Participant's separation from service of his or her own volition and one or more of the following conditions occurs without the Participant's consent on or after a Change of Control:

(a) There is a material diminution in the Participant's base compensation, compared to his or her rate of base compensation on the date of the Change of Control.

(b) There is a material diminution in the Participant's authority, duties, or responsibilities.

(c) There is a material diminution in the authority, duties, or responsibilities of the Participant's supervisor, such as a requirement that the Participant (or his or her supervisor) report to a corporate officer or employee instead of reporting directly to the board of directors.

(d) There is a material diminution in the budget over which the Participant retains authority.

(e) There is a material change in the geographic location at which the Participant must perform his or her service, including, for example the assignment of the Participant to a regular workplace that is more than 50 miles from his or her regular workplace on the date of the Change of Control.

The Participant must notify the Company of the existence of one or more adverse conditions specified in clauses (a) through (e) above within 90 days of the initial existence of the adverse condition. The notice must be provided in writing to the Company or its successor, attention: Head of Human Resources. The notice may be provided by personal delivery or it may be sent by email, inter-office mail, regular mail (including certified), fax, or any similar method. The Company's Head of Human Resources or his or her delegate shall acknowledge receipt of the notice within 5 business days; the acknowledgement shall be sent to the Participant by certified mail. Notwithstanding the foregoing provisions of this definition, if the Company

remedies the adverse condition within 30 days of being notified of the adverse condition, no Voluntary Termination with Cause shall occur.

"**Years of Service**" means the total number of months from the Participant's date of hire by the Company to the date of termination of employment, plus any months required to be recognized under an appropriate acquisition agreement, divided by 12.

Terms

1. **Conditional Grant of RSUs and Cash Award**. Subject to the provisions of this Agreement and the provisions of the Plan and Grant Notice, the Company shall conditionally grant to the Participant, pursuant to the Plan, the right to receive the Target RSUs and the Target Cash Award. Such Target RSUs and Target Cash Award shall be adjusted to a Final RSU Amount and Final Cash Award Amount at the end of the Performance Period based upon the results of the applicable Performance Measures, as determined by the Committee. Notwithstanding the foregoing, the Target RSUs and Target Cash Award shall be adjusted to a Final RSU Amount and Final Cash Award Amount at the conclusion of the Performance Period solely for each Participant who remains employed or is deemed to be employed on account of Retirement as of the last day of the Performance Period. The award of the Final Amount shall give the Participant the right, upon vesting, to receive an amount of cash equal to the sum of (a) the Fair Market Value of an equal number of shares of $0.625 par value common stock of the Company ("**Stock**") to that of the number of RSUs comprising the Final RSU Amount and (b) an amount of cash equal to the Cash Award comprising the Final Cash Award Amount.

2. **Vesting and Payment of Cash**. Subject to the provisions of sections 3, 4, and 5, the Payout Amounts shall be payable in increments strictly in accordance with the schedule set forth in the Grant Notice; *provided* that the Participant remains employed as an Eligible Person on such applicable vesting dates. Except as otherwise provided herein, such cash, subject to applicable withholding, shall be paid by the Company to the Participant within sixty (60) days of such vesting date.

3. **Termination of Employment, Retirement, Death, or Disability prior to the end of the Performance Period**. Except as set forth below, a cessation of employment with the Company prior to the end of the Performance Period will result in the Target RSUs and Target Cash Award being forfeited for all purposes.

   (a) If the Participant dies while employed by the Company regardless of whether Participant has accepted the Conditional Grants, or if the Participant is no longer employed by the Company by reason of Disability (as defined in this Agreement), during the Performance Period, the Participant shall be entitled to an amount equal to the Target RSUs and the Target Cash Award and shall become 100% vested therein. Payment shall be made as soon as administratively practicable, but in no event (i) in the case of death, shall the payment occur later than the last day of the calendar year following the calendar year in which such death occurs or (ii) in the case of cessation of employment by reason of Disability, shall the payment occur later than thirty (30) days following the date upon which the Participant is Disabled and is no longer employed by the Company. If clause (ii) is applicable and the payment period spans two consecutive calendar years, payment shall be made in the second calendar year of such consecutive calendar years. Such payment shall be made to the Participant's designated beneficiary, legal representatives, heirs, or legatees, as applicable. Each Participant may designate a beneficiary on a form approved by the Committee.

   (b) If the Participant leaves the employment of the Company by reason of Retirement after the first three (3) months of the Performance Period (and not before) and prior to the end of the Performance Period, any Final RSU Amount and any Final Cash Award Amount not previously vested shall continue to vest following the Participant's termination of employment by reason of Retirement as if the Participant remained an Eligible Person in the employ of the Company until the vesting dates set forth in section 2 above, *provided* that such Participant shall be entitled to continue vesting only if

such Participant satisfies the Retirement conditions set forth in section 6 below (except in the case of death) and only with respect to the specified percentage of any such unvested Final RSU Amount or Final Cash Award Amount set forth in Exhibit A for a certain combination of age and Years of Service attained by the Participant as of the Participant's Retirement under the matrix set forth in Exhibit A. An amount of cash equal to the sum of (i) the Fair Market Value of an equal number of shares of Stock and (ii) an amount of cash equal to the Cash Award, in each case, that vests pursuant to this section 3(b) and subject to applicable withholding, shall be paid by the Company to the Participant who is retired, within sixty (60) days of such vesting date.

4. **Termination of Employment, Retirement, Death or Disability after the end of the Performance Period**. Except as set forth below, each Conditional Grant shall be subject to the condition that the Participant has remained an Eligible Person from the award of the Conditional Grant of RSUs and the Cash Award until the applicable vesting date as follows:

   (a) If the Participant voluntarily leaves the employment of the Company (other than for reason of Retirement), or if the employment of the Participant is terminated by the Company for any reason or no reason, any Final Amounts not previously vested shall thereafter be void and forfeited for all purposes.

   (b) A Participant shall become 100% vested in any Final RSU Amount and any Final Cash Award Amount on the date the Participant dies while employed by the Company regardless of whether Participant has accepted the Conditional Grant (or while continuing to vest pursuant to section 4(c) below), or on the date the Participant is no longer employed by the Company by reason of Disability. Payment shall be made as soon as administratively practicable, but in no event (i) in the case of death, shall the payment occur later than the last day of the calendar year following the calendar year in which such death occurs or (ii) in the case of cessation of employment by reason of Disability, shall the payment occur later than thirty (30) days following the date the Participant is determined to be Disabled and is no longer employed by the Company. If clause (ii) is applicable and the payment period spans two consecutive calendar years, payment shall be made in the second calendar year of such consecutive calendar years. Such payment shall be made to the Participant's designated beneficiary, legal representatives, heirs, or legatees, as applicable. Each Participant may designate a beneficiary on a form approved by the Committee.

   (c) If the Participant leaves the employment of the Company by reason of Retirement after the end of the Performance Period, any Final RSU Amount and any Final Cash Award Amount not previously vested shall continue to vest following the Participant's termination of employment by reason of Retirement after the end of the Performance Period as if the Participant remained an Eligible Person in the employ of the Company until the vesting date set forth in section 2 above, *provided* that such Participant shall be entitled to continue vesting only if such Participant satisfies the Retirement conditions set forth in section 6 below (except in the case of death) and only with respect to the specified percentage of such unvested Final Amounts set forth in Exhibit A for a certain combination of age and Years of Service attained by the Participant as of the Participant's Retirement under the matrix set forth in Exhibit A. An amount of cash equal to the sum of (i) the Fair Market Value of an equal number of shares of Stock and (ii) an amount of cash equal to the Cash Award, in each case, that vests pursuant to this section 4(c) and subject to applicable withholding, shall be paid by the Company to the Participant who is retired, within sixty (60) days of such vesting date.

5. **Change of Control**.

   (a) Pursuant to Section 13.1(c)(iii) and (d) of the Plan, the following provisions of this section 5 of the Agreement shall supersede Sections 13.1(a), (b) and (c) of the Plan. Without any further action by the Committee or the Board, in the event of the Participant's Involuntary Termination or Voluntary Termination with Cause occurring (i) on or after a Change of Control and (ii) prior to the end of the

Performance Period, the Participant shall become 100% vested in the Target RSUs and the Target Cash Award as of the date of such Involuntary Termination or Voluntary Termination with Cause. Subject to section 12(b) of this Agreement, payment shall occur within thirty (30) days of the date of such Involuntary Termination or Voluntary Termination with Cause, subject to required tax withholding.

(b) In the event of a Participant's Involuntary Termination or Voluntary Termination with Cause occurring on or after a Change of Control that occurs after the end of the Performance Period, the Participant shall become 100% vested in the Final RSU Amount and the Final Cash Award Amount as of the date of such Involuntary Termination or Voluntary Termination with Cause. Subject to section 12(b) of this Agreement, payment shall occur within thirty (30) days of the date of such Involuntary Termination or Voluntary Termination with Cause, subject to required tax withholding.

(c) In the event of a Change of Control following the Participant's termination of employment by reason of Retirement after the first three (3) months of the Performance Period and ending on the last day of the Vesting Period, the Participant shall become 100% vested in the unvested Final RSU Amount and the unvested Final Cash Award Amount, each as of the date of the Change of Control. Subject to section 12(b) of this Agreement, payment shall occur within thirty (30) days of a 409A Change of Control; *provided* that if no 409A Change of Control occurs during the Performance Period, nor during the period of continued vesting as set forth in sections 3(b) and 4(c) of this Agreement, then the Final Amount shall be paid by the Company to the Participant who is retired within sixty (60) days of the vesting dates (in the applicable percentage amounts) set forth in section 2 of this Agreement, subject to required tax withholding. In the event of a Change of Control prior to the Participant's termination of employment by reason of Retirement and after the first three (3) months of the Performance Period and ending on the last day of the Vesting Period, the Participant shall become 100% vested in the unvested Final RSU Amount and the unvested Final Cash Award Amount, each as of the date that the Participant terminates employment by reason of Retirement. For the purpose of vesting as set forth in the prior sentence, a Participant's Involuntary Termination or Voluntary Termination with Cause after a Change of Control shall be deemed a termination by reason of Retirement. Subject to section 12(b) of this Agreement, if the Participant terminates employment by reason of Retirement after a Change of Control, the Participant shall receive payment with respect to 100% of the Final Amount within sixty (60) days of the vesting dates (in the applicable percentage amounts) as set forth in section 2 of this Agreement, subject to required tax withholding.

6. Conditions to Post-Retirement Vesting.

(a) ***Continued Vesting***. If the Participant has attained age 55 and a certain combination of age and Years of Service set forth in the matrix in Exhibit A attached hereto and terminates employment with the Company and the Affiliates by reason of Retirement after the first three (3) months of the Performance Period, it is agreed by the Company and the Participant that, subject to the provisions of this section 6(a) and section 6(b), such Participant shall continue to vest in the specified percentage of the unvested Final RSU Amount and the Final Cash Award Amount set forth in Exhibit A for the combination of age and Years of Service attained by such Participant as of his or her Retirement under the matrix set forth in Exhibit A following the date of his or her termination by reason of Retirement as if the Participant continued in employment; *provided* that the Grant Date of the unvested RSUs and the Cash Award is prior to such termination date in an amount of time that allows the Participant to provide the written notice as follows and the Participant has provided advance written notice not before three (3) months following the Grant Date and not less than the number of months prior to such termination date as set forth in the schedule below to the Company's Head of Human Resources or his or her delegate, and to his or her direct manager, regarding the Participant's intent to terminate employment for reason of Retirement (the period commencing on the first day following the first three (3) months of the Performance Period and ending on the last day of the Vesting Period being the "**Continued Vesting Period**"); *provided,*

however, a Participant who is at least age 55 and attained the necessary combination of age and Years of Service under the matrix set forth in Exhibit A for Retirement need not provide such advance written notice of his or her intent to terminate employment by reason of Retirement if the Company elects to require such Participant to, or (as part of a reduction in force or otherwise in writing in exchange for a written release) offers such Participant the opportunity to, terminate employment with the Company by reason of Retirement.

Age	Advance Written Notice
65 or older	3 months
between (and including) 55 and 64	6 months

(b) ***Restrictions***. In consideration of the benefit provided under paragraph (a) above, it is agreed by the Company and the Participant that, during the Continued Vesting Period, the Participant shall comply with the following restrictions.

(i) *No Competitive Business*. The Participant shall refrain from becoming employed by, or consulting with, or becoming substantially involved in the business of, any business that competes with the Company or its Affiliate in the business of exploration or production of oil or natural gas wherever from time to time conducted throughout the world (a "**Competitive Business**") and Participant shall provide to the Company, upon Company's request, (x) a written certification, in a form provided by or satisfactory to the Company, as to Participant's compliance with the forgoing conditions and/or (y) his/her U.S. Individual Income Tax Return for any return filed by the Participant which relates to any time during the Continued Vesting Period to allow the Company to verify that Participant has complied with the foregoing conditions; *provided*, that the Participant may purchase and hold for investment purposes less than five percent (5%) of the shares of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system, and *provided further*, that the Participant may provide services solely as a director of any Competitive Business whose shares are regularly traded on a national securities exchange or inter-dealer quotation system if, during the Continued Vesting Period, (i) the Participant only attends board and board committee meetings, votes on recommendations of management, and discharges his/her fiduciary obligations under the law and (ii) the Participant is not involved in, and does not advise or consult on, the marketing, government relations, customer relations, or the day-to-day management, supervision, or operations of such Competitive Business.

(ii) *Non-Disparagement*. The Participant shall refrain from making, or causing or assisting any other person to make, any oral or written communication to any third party about the Company, any Affiliate and/or any of the employees, officers, or directors of the Company or any Affiliate that impugns or attacks, or is otherwise critical of, the reputation, business, or character of such entity or person; or that discloses private or confidential information about their business affairs; or that constitutes an intrusion into their seclusion or private lives; or that gives rise to unreasonable publicity about their private lives; or that places them in a false light before the public; or that constitutes a misappropriation of their name or likeness.

(c) ***Failure to Comply and Future Awards***. Notwithstanding the foregoing provisions of this section 6 of the Agreement, (i) in the event that the Participant fails to satisfy any of the conditions set forth in paragraphs (a) and/or (b) above, the Participant shall not be entitled to vest in the specified percentage under the matrix set forth in Exhibit A in any unvested Final RSU Amount or the unvested Final Cash Award Amount after the date of Retirement and the unvested Final RSU Amount and the unvested Final Cash Award Amount subject to this Agreement shall be forfeited and (ii) the Participant shall not have any right to continue to vest upon Retirement in any future awards granted

under the Plan once the Participant provides the notice of Retirement as set forth in paragraph (a) above.

7. **Prohibited Activity**. In consideration for this Conditional Grant and except as permitted under section 6(b)(i) above, the Participant agrees not to engage in any Prohibited Activity while employed by the Company or within three years after the date of the Participant's termination of employment. A "**Prohibited Activity**" will be deemed to have occurred, as determined by the Committee in its sole and absolute discretion, if any of the following occur.

   (a) ***Disclosure of Confidential Information***. The Participant divulges any non-public, confidential, or proprietary information of the Company, but excluding information that (i) becomes generally available to the public other than as a result of the Participant's public use, disclosure, or fault or (ii) becomes available to the Participant on a non-confidential basis after the Participant's employment termination date from a source other than the Company prior to the public use or disclosure by the Participant, *provided* that such source is not bound by a confidentiality agreement or otherwise prohibited from transmitting the information by contractual, legal, or fiduciary obligation.

   (b) ***Competitive Business***. The Participant, directly or indirectly, consults with or becomes affiliated with, participates or engages in, or becomes employed by any business that is competitive with the Company, wherever from time to time conducted throughout the world, including situations where the Participant solicits or participates in or assists in any way in the solicitation or recruitment, directly or indirectly, of any employees of the Company.

   (c) ***Disparagement***. The Participant engages in publishing any oral or written statements about the Company, and/or any of its directors, officers, or employees that are disparaging, slanderous, libelous, or defamatory; or that disclose private or confidential information about their business affairs; or that constitute an intrusion into their seclusion or private lives; or that give rise to unreasonable publicity about their private lives; or that place them in a false light before the public; or that constitute a misappropriation of their name or likeness.

8. **Payment and Tax Withholding**. Upon receipt of any entitlement to cash under this Agreement and, if applicable, upon the Participant's attainment of eligibility to terminate employment by reason of Retirement pursuant to section 4(c), the Participant shall make appropriate arrangements with the Company to provide for the amount of minimum tax and social security withholding, if any, required by law, including without limitation Sections 3102 and 3402 or any successor section(s) of the Code and applicable state and local income and other tax laws. The payment of a Payout Amount shall be based on the sum of (a) the Fair Market Value of the shares of Stock on the applicable date of vesting and (b) an amount of cash equal to the Cash Award to which such tax withholding relates. Where appropriate, cash shall be withheld by the Company to satisfy applicable tax withholding requirements rather than paid directly to the Participant.

9. **Non-Transferability of Conditional Grant and Unvested Final Amount**. The Conditional Grant and any unvested Final Amount shall not be transferable otherwise than by testamentary will or the laws of descent and distribution, or in accordance with a valid beneficiary designation on a form approved by the Committee, subject to the conditions and exceptions set forth in Section 15.2 of the Plan.

10. **No Right to Continued Employment**. Neither the RSUs, the Cash Award, or the cash payment pursuant to a Conditional Grant nor any terms contained in this Agreement shall confer upon the Participant any express or implied right to be retained in the employment or service of the Company for any period, nor restrict in any way the right of the Company, which right is hereby expressly reserved, to terminate the Participant's employment or service at any time for any reason or no reason. The Participant acknowledges and agrees that any right to receive RSUs, the Cash Award, or cash pursuant to a Conditional Grant is earned only by continuing as an employee of the Company at the will of the

Company, or satisfaction of any other applicable terms and conditions contained in the Plan and this Agreement, and not through the act of being hired, being granted the Conditional Grant, or acquiring RSUs, the Cash Award, or cash pursuant to the Conditional Grant hereunder.

11. The Plan. In consideration for these Conditional Grants, the Participant agrees to comply with the terms of the Plan and this Agreement. This Agreement is subject to all the terms, provisions and conditions of the Plan, which are incorporated herein by reference, and to such regulations as may from time to time be adopted by the Committee. The Conditional Grants are Cash-Based Awards under Section 10 of the Plan and are subject to the provisions of the Plan governing Performance Awards. Unless defined herein, capitalized terms are used herein as defined in the Plan. In the event of any conflict between the provisions of the Plan and this Agreement, the provisions of the Plan shall control, and this Agreement shall be deemed to be modified accordingly. The Plan and the prospectus describing the Plan can be found on the Company's HR intranet and the Fidelity website (netbenefits.fidelity.com). A paper copy of the Plan and the prospectus shall be provided to the Participant upon the Participant's written request to the Company at 2000 W. Sam Houston Pkwy S., Suite 200, Houston, Texas 77042, Attention: Corporate Secretary.

12. Compliance with Laws and Regulations.

(a) ***Applicable Laws***. The Conditional Grants and any obligation of the Company to deliver RSUs, the Cash Award, and cash hereunder shall be subject in all respects to (i) all applicable laws, rules, and regulations and (ii) any registration, qualification, approvals, or other requirements imposed by any government or regulatory agency or body which the Committee shall, in its discretion, determine to be necessary or applicable.

(b) ***Code Section 409A***. These Conditional Grants are intended to comply with, or be exempt from, the applicable requirements of Section 409A of the Code and the rules and regulations issued thereunder and shall be administered accordingly. Notwithstanding anything in this Agreement to the contrary, if the RSUs or Cash Award constitute "deferred compensation" under Section 409A of the Code and any RSUs or the Cash Award become payable pursuant to the Participant's termination of employment, settlement of the RSUs and the Cash Award shall be delayed for a period of six months after the Participant's termination of employment if the Participant is a "specified employee" as defined under Code Section 409A(a)(2)(B)(i) and if required pursuant to Section 409A of the Code. If settlement of the RSUs and Cash Award is delayed, the RSUs and Cash Award shall be settled on the first day of the first calendar month following the end of the six-month delay period. If the Participant dies during the six-month delay, the RSUs and Cash Award shall be settled and paid to the Participant's designated beneficiary, legal representatives, heirs or legatees, as applicable, as soon as practicable after the date of death. Notwithstanding any provision to the contrary herein, payments made with respect to these Conditional Grants may only be made in a manner and upon an event permitted by Section 409A of the Code, and all payments to be made upon a termination of employment hereunder may only be made upon a "separation from service," as such term is defined in Section 11.1 of the Plan. Participant shall not have any right to determine a date of payment of any amount under this Agreement. This Agreement may be amended without the consent of the Participant in any respect deemed by the Board or the Committee to be necessary in order to preserve compliance with Section 409A of the Code. If the Conditional Grant and this Agreement is subject to Section 409A of the Code and the rules and regulations issued thereunder, and, except as set forth in section 5(a), the vesting date shall be the "designated payment date" or "specified date" under Treasury Regulation 1.409A-3(d).

13. Notices. Unless otherwise provided in this Agreement, all notices by the Participant or the Participant's assignees shall be addressed to the Administrative Agent, Fidelity, through the Participant's account at netbenefits.fidelity.com, or such other address as the Company may from time to time specify. All

notices to the Participant shall be addressed to the Participant at the Participant's address in the Company's records.

14. **Other Plans**. The Participant acknowledges that any income derived from the Conditional Grant shall not affect the Participant's participation in, or benefits under, any other benefit plan or other contract or arrangement maintained by the Company or any Affiliate.

15. **Terms of Employment**. The Plan is a discretionary plan. The Participant hereby acknowledges that neither the Plan nor this Agreement forms part of the Participant's terms of employment and nothing in the Plan may be construed as imposing on the Company or any Affiliate a contractual obligation to offer participation in the Plan to any employee of the Company or any Affiliate. The Company or any Affiliate is under no obligation to make further grants to any Participant under the Plan. The Participant hereby acknowledges that if the Participant ceases to be an employee of the Company or any Affiliate for any reason or no reason, the Participant shall not be entitled by way of compensation for loss of office or otherwise howsoever to any sum or other benefit to compensate the Participant for the loss of any rights under this Agreement or the Plan.

16. **Data Protection**. By accepting this Agreement (whether by electronic means or otherwise), the Participant hereby consents to the holding and processing of personal data provided by the Participant to the Company for all purposes necessary for the operation of the Plan. These include, but are not limited to:

    (a) administering and maintaining Participant records;

    (b) providing information to any registrars, brokers, or third-party administrators of the Plan; and

    (c) providing information to future purchasers of the Company or the business in which the Participant works.

17. **Clawback Policy**. If required by the Sarbanes-Oxley Act of 2002 and/or by the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, each Participant's Award shall be conditioned on repayment or forfeiture in accordance with applicable law. In addition, the Company's Executive Compensation Clawback Policy is hereby incorporated by reference and shall form a part of this Agreement and each Participant's Award shall be subject to such policy. In connection with an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the U.S. federal securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period, Awards and payments in connection with Awards granted under this Agreement may be subject to recovery and Participant may be required to repay to the Company all or a portion of any Award or payments received in connection with any Award hereunder. In the event that the Company determines to seek recovery with respect to an Award under this Agreement, the Company will determine the appropriate means of recovery, which may vary, without limitation, between Participants or based on the nature of the applicable incentive compensation, and which may involve, without limitation, establishing a deferred repayment plan or set off against current or future compensation otherwise payable to an affected Participant. The amount of any applicable repayment shall be determined without regard to income taxes paid by the Participant or by the Company on the Participant's behalf in connection with such Award; *provided*, *however*, the Participant may be entitled, if allowed under applicable laws, rules, and regulations, to a deduction for the tax year within which such amounts are repaid, and as a result, the timing of recovering the tax refund portion of such Award pursuant to the foregoing sentence shall (to the maximum extent practicable) be deferred to incorporate the timing of any such tax refund.

18. **Severability**. If any provision of this Agreement is held invalid or unenforceable, the remainder of this Agreement shall nevertheless remain in full force and effect, and if any provision is held invalid or unenforceable with respect to particular circumstances, it shall nevertheless remain in full force and effect in all other circumstances, to the fullest extent permitted by law.

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APA Corporation
Executive Compensation Clawback Policy

OUR POLICY

The Company has adopted this Policy for the purpose of complying with the applicable recoupment provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act). This Policy applies to Incentive Compensation that is Received by a Covered Individual on or after October 2, 2023 (the Effective Date).

Recoupment Trigger

If the Company is required to prepare an Accounting Restatement, then the Company shall recover, reasonably promptly from each Covered Individual, any Erroneously Awarded Compensation that was Received by such Covered Individual during the Look-Back Period. Notwithstanding anything herein to the contrary, this Policy shall be deemed automatically and unilaterally amended to the minimum extent necessary to comply with the applicable listing standards to which the Company is listed.

The Committee may at any time suspend, amend, or terminate this Policy to the minimum extent necessary to comply with applicable laws. The Committee has the sole discretion to interpret and enforce this Policy, which will be interpreted to be automatically amended to the minimum extent necessary to comply with the provisions of the Dodd-Frank Act's clawback requirements.

Enforcement and Impracticability

The Committee shall recover any Incentive Compensation in accordance with this Policy unless such recovery would be impracticable, as determined by the Committee in accordance with Rule 10D-1 of the Securities Exchange Act of 1934, as amended (the Exchange Act), and the listing standards of the national securities exchange on which the Company's securities are listed. To the extent the Committee determines to enforce recoupment, (i) the Committee shall provide the Covered Individual written notice of its intent to recoup Incentive Compensation under this Policy, along with a reasonable timeline within which the Covered Individual must respond given all the applicable facts and circumstances, (ii) to the extent the Covered Individual does not intend to comply with such recoupment efforts, he or she must respond to the Committee in writing detailing the reasons why non-compliance is warranted and such response must be provided to the Committee within fifteen (15) business days from the Covered Individual receiving the Committee's initial notice, and (iii) if the Committee disagrees with the Covered Individual's assertions, then the Committee must respond to the Covered Individual in writing detailing such reasons within the fifteen (15) business days immediately following its receipt of the Covered Individual's written response.

Means of Recovery

With respect to recovery of Erroneously Awarded Compensation and subject to the requirement that recovery be made reasonably promptly, the Committee will determine the appropriate means of recovery, which may vary, without limitation, between Covered Individuals or based on the nature of the applicable Incentive Compensation, and which may involve, without limitation, establishing a deferred repayment plan or set off against current or future compensation otherwise payable to the Covered Person.

Recovery of Erroneously Awarded Compensation will be made without regard to income taxes paid by the Covered Individual or by the Company on the Covered Individual's behalf in connection with such Erroneously Awarded Compensation; provided, however, the Covered Individual may be entitled to a deduction (pursuant to the "claim of right doctrine" or Section 1341 of the Internal Revenue Code of 1986, as amended) for the tax year within which Erroneously Awarded Compensation is repaid, and as a result, the timing of recovering the tax refund portion of Erroneously Awarded Compensation pursuant to the foregoing

sentence shall (to the maximum extent practicable) be deferred to incorporate the timing of any such tax refund.

Compensation Not Covered by this Policy

This Policy does not apply to Incentive Compensation that was Received before the Effective Date and does not apply to Incentive Compensation that was Received by a Covered Individual before becoming a Covered Individual.

No Indemnification or Company-Paid Insurances

The Company will not indemnify or reimburse any Covered Individual against or for the loss of Erroneously Awarded Compensation and will not pay or reimburse any Covered Individual for the purchase of a third-party insurance policy to fund potential recovery obligations.

Defined Terms

Except as otherwise provided above, the following definitions apply to this Policy:

Accounting Restatement means a requirement that the Company prepare an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the U.S. federal securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period. Changes to the Company's financial statements that do not represent error corrections are not an Accounting Restatement, including (i) retrospective application of a change in accounting principle, (ii) retrospective revision to reportable segment information due to a change in the structure of the Company's internal organization, (iii) retrospective reclassification due to a discontinued operation, (iv) retrospective application of a change in reporting entity, such as from a reorganization of entities under common control, and (v) retrospective revision for stock splits, reverse stock splits, stock dividends, or other changes in capital structure.

Company means APA Corporation, a Delaware corporation.

Covered Individual means, whether former or current, the (i) named executive officers of the Company, (ii) each "executive officer" of the Company (as such term is defined under Section 16 of the Exchange Act), and (iii) any other officer of the Company or any of its subsidiaries that is designated by the Committee as being subject to this Policy prior to the Company's discovery of the Accounting Restatement.

Erroneously Awarded Compensation means the amount of Incentive Compensation that was Received that exceeds the amount of Incentive Compensation that otherwise would have been Received had the amount of Incentive Compensation been determined based on the restated Financial Reporting Measures, computed without regard to any taxes paid by the Covered Individual, reduced by the amount of such Incentive Compensation that is recovered by the Company from such Covered Individual pursuant to Section 304 of Sarbanes-Oxley Act of 2002, any other law, rule or regulation, or any other means. For Incentive Compensation based on total shareholder return or Company stock price, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in an Accounting Restatement, the amount of Erroneously Awarded Compensation will be based on a reasonable estimate by the Committee of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the Incentive Compensation was Received. The Company will maintain documentation of the determination of that reasonable estimate and provide such documentation to Nasdaq if required.

Financial Reporting Measures means (i) measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements and any measures that are derived wholly or in part from such measures (whether or not such measures are presented within the Company's financial statements or included in a filing made with the U.S. Securities and Exchange Commission), (ii) Company stock price, and (iii) Company total shareholder return.

Incentive Compensation means the following compensation to the extent earned, paid, granted, or vested wholly (or in part) upon the attainment of any Financial Reporting Measure of the Company: a Covered Individual's cash bonus awarded under the Company's annual incentive plan and any equity-based awards granted pursuant to the Company's long-term incentive plans (including cash or stock dividends paid on such equity-based awards).

Look-Back Period means the three completed fiscal years immediately preceding the earlier of (i) the date the Company's Board of Directors (the Board), a committee of the Board, or the officer or officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement. In addition, if there is a change in the Company's fiscal year end, the Look-Back Period will also include any transition period to the extent required by Nasdaq Rule 5608.

Received means, with respect to Incentive Compensation of a Covered Individual, the fiscal year to which the Financial Reporting Measure is attained, irrespective of whether the Incentive Compensation is subject to additional time or non-financial performance vesting conditions.

Exhibit A

Age at Retirement	Points (Age at Retirement + Years of Service)																			
	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80
70	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%
69	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%
68	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%
67	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%
66	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
65	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
64	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
63	0%	0%	0%	0%	0%	0%	0%	0%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
62	0%	0%	0%	0%	0%	0%	0%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
61	0%	0%	0%	0%	0%	0%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
60	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	100%
59	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
58	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
57	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
56	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%
55	0%	0%	0%	0%	0%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	75%	75%	75%	75%	75%	100%

APA Corporation

Insider Trading Policy

This Insider Trading Policy (this "**policy**") applies to (i) all officers, directors, and employees of APA Corporation and its subsidiaries and affiliates worldwide (collectively, the "**Company**"), (ii) all contractors, consultants, agents, and advisors of the Company, (iii) all other persons and entities who may from time to time have access to the Company's material nonpublic information (information that has a substantial likelihood that a reasonable investor would consider it important in deciding to buy, sell, or hold the Company's securities and that has not been widely disseminated, such as through a press release or other public disclosure) and are designated by the Company as being subject to this policy (such persons and entities, collectively with the persons identified in clauses (i) and (ii) above, the "**Covered Persons**"), and (iv) all family members of, persons sharing the household of, and entities controlled by a Covered Person (such family members, other persons, and entities, collectively, the "**Related Persons**").

The insider trading and other anti-fraud provisions of the federal securities laws restrict your ability to trade in Company securities while you are in possession of material nonpublic information that you acquire in the course of working for the Company (also referred to as "**inside information**"). These laws also limit your ability to share inside information with others, including members of your family and your fellow employees. Violations of the federal securities laws can carry severe civil and criminal penalties for the Company and for you personally, so please read this policy carefully.

What Transactions are Subject to this Policy?

This policy applies to all purchases, sales, and bona fide gifts of Company securities, including the Company's common stock ("**common stock**"), options to purchase common stock, and other securities and derivative securities the Company may issue from time to time, including preferred stock, convertible notes, and warrants, as well as any derivative securities issued by third parties that relate to Company securities.

Who Administers this Policy?

The Company's office of the corporate secretary is responsible for administering this policy, and the Company's corporate secretary (including any assistant secretary delegated responsibilities hereunder by the corporate secretary) is responsible for interpretations of and determinations under this policy. Any such determination or interpretation by the corporate secretary shall be final and not subject to further review.

What is the Company's Policy?

It is the policy of the Company that no Covered Person who is aware of material nonpublic information about the Company may, directly or indirectly through family members or other Related Persons:

- engage in transactions in Company securities, except as expressly permitted under "Are There Exceptions to this Policy?" below;
- recommend that others engage in transactions in Company securities;
- use such information to his or her advantage; or
- disclose such material nonpublic information.

It is also the policy of the Company that no Covered Person who, in the course of working for the Company, becomes aware of material nonpublic information about another company with which the

Company (i) does, or proposes to do, business (such as a customer, supplier, distributor, or vendor) or (ii) is engaged, or proposes to engage, in a transaction (such as an acquisition, divestiture, merger, or joint venture) or other business relationship (all such activities, collectively, "**business relationships**") may engage in transactions in such other company's securities until such material nonpublic information becomes public or is no longer material. There are no exceptions to this policy, except as specifically referenced above and set forth herein.

What is Material Information?

Information is material to the Company if there is a substantial likelihood that a reasonable investor would consider it important in deciding to buy, sell, or hold the Company's securities. Any information that could be expected to impact the Company's stock price (whether positively or negatively) should be considered material. While there is no bright-line test for assessing materiality, the following are examples of information that would normally be considered material:

- dividend increases or decreases,
- earnings estimates,
- changes in previously announced earnings estimates,
- significant expansions or curtailments of operations,
- significant increases or declines in business,
- significant merger, acquisition, or joint venture discussions,
- significant new services or discoveries,
- significant asset write-downs (or write-ups),
- unusual borrowings or securities offerings,
- major litigation,
- liquidity problems,
- availability of credit (or lack of availability),
- extraordinary managerial developments,
- purchases or sales of significant assets, and
- significant cybersecurity incidents.

This list is not exhaustive, and other information concerning the Company, its prospects or activities may be material depending on the facts and circumstances. If you are not sure if the information you possess is material, then please contact the corporate secretary to discuss.

What are Your Responsibilities Under this Policy?

Your Transactions

You are responsible for complying with this policy and for determining if you are in possession of material nonpublic information prior to trading in Company securities. If you are (or are later deemed to be) in possession of material nonpublic information at the time of a transaction, then no action taken by the Company, the corporate secretary, or any other officer, director, or employee of the Company, pursuant to this policy or otherwise, can or will shield you from a violation of this policy or the federal securities laws.

Transactions by Your Related Persons

You are responsible not only for your transactions in Company securities, but also for transactions by your Related Persons, including members of your family, other persons who share your household, and entities that you control (including corporations, partnerships, limited liability companies, and trusts, among others). For purposes of this policy and the federal securities laws, you should treat transactions by your Related Persons as if they were transactions for your own account. As such, it is important that you make your Related Persons aware of this policy, the federal securities laws, and your and their obligations hereunder and thereunder.

Transactions by Your Subordinates

If you are a supervisor or manager, then you may also be responsible for insider trading violations by your subordinates, if you (i) know or recklessly disregard the fact that the subordinate is likely to engage in insider trading and (ii) fail to take steps to prevent the violation before it occurs. This means supervisor or manager must not only exercise caution in their own trading but must also carefully supervise any subordinates who routinely have access to material nonpublic information. If you believe a subordinate has violated, is violating, or may violate this policy or the federal securities laws, then you should alert the corporate secretary immediately.

Are There Exceptions to this Policy?

Transactions Under Company Plans or with the Company

Regularly scheduled purchases of Company common stock, which are automatically made in accordance with your prior elections, under the Company's Dividend Reinvestment Plan, Non-Qualified Retirement/Savings Plan, or Non-Qualified Restorative Retirement Savings Plan (each, a "**Company plan**") will not constitute insider trading, even if you possess material nonpublic information at the time of purchase, as long as you did not possess material nonpublic information at the time you made the election. However, you cannot make any new elections under a Company plan during a blackout period or while you are in possession of material nonpublic information. Additionally, transactions in Company securities with the Company, including purchases of Company securities from the Company and sales of Company securities to the Company, are not subject to this policy.

Equity Award Transactions

The following types of transactions involving awards issued under the Company's equity compensation plans that do not involve a discretionary market sale of Company securities are not subject to the trading or preclearance restrictions in this policy:

- the vesting, settlement, or payout of restricted stock, restricted stock units, performance shares, or other equity awards;
- the withholding or surrender of shares to satisfy tax-withholding obligations upon the vesting, settlement, or exercise of any equity award;
- the exercise of stock options for cash or through any Company-administered net or cashless exercise program; and
- the automatic forfeiture or expiration of equity awards.

Any open-market sale of shares received in connection with an equity award transaction, including the sale of stock underlying an option, any broker-assisted cashless exercise of stock options, or any other market sale of Company securities for the purpose of generating the cash needed to pay the exercise price or tax withholding related to a stock option, remains subject to all provisions of this policy, including applicable blackout periods and preclearance requirements.

Transactions Under Rule 10b5-1 Plans

Rule 10b5-1 under the Securities Exchange Act of 1934, as amended, provides an affirmative defense to insider trading liability for a person who trades in Company securities under a trading plan adopted in good faith and at a time when he or she did not possess material nonpublic information about the Company (a "**plan participant**"). In order to rely on the defense provided by Rule 10b5-1, a Covered Person must have an effective trading plan for transactions in Company securities that meets certain conditions set forth in Rule 10b5-1 (a "**Rule 10b5-1 plan**"). All Rule 10b5-1 plans must be approved in advance by the corporate secretary. If you have questions regarding Rule 10b5-1 plans or would like to request preapproval of a Rule 10b5-1 plan, then please contact the corporate secretary to discuss.

When Can You Trade?

The Company has chosen not to implement Company-wide policies such as blackout periods and mandatory preclearance procedures for its employees, except as expressly provided under "Are You Subject to Additional Restrictions?" below. Under this policy and the federal securities laws, you are responsible for determining if you are in possession of material nonpublic information prior to trading in Company securities. Even after material information is publicly disclosed by the Company, it is important not trade in Company securities until sufficient time has elapsed for the information to be fully disseminated to, and absorbed by, the market.

As a general rule, information should not be considered fully absorbed by the market until one full trading day following its public release. For example, if the Company issues a press release before the markets open on a Monday, then you could begin trading when the markets open on Tuesday. Alternatively, if the Company issues a press release after the markets close on a Monday, then you could begin trading when the markets open on Wednesday.

Are You Subject to Additional Restrictions?

Certain Covered Persons who routinely have access to the Company's material nonpublic information, including the Company's directors and executive officers and certain other officers and specified employees designated in writing from time to time by the corporate secretary (collectively, "**Restricted Persons**"), are subject to additional restrictions and procedures that do not apply to other Covered Persons under this policy. These restrictions and procedures are intended to facilitate compliance with this policy and the federal securities laws, and to avoid even the appearance of impropriety, when such Restricted Persons are (or may be deemed to be) in possession of material nonpublic information.

Quarterly Blackout Periods

Restricted Persons who are notified by the corporate secretary in writing as being subject to the Company's quarterly blackout periods (and their Related Persons) may not engage in transactions in

Company securities during the period beginning on the first day of each fiscal quarter and ending one full trading day following the Company's public release of its earnings results for the prior quarter or fiscal year (in the case of the fourth quarter). The Company's typical practice is to issue earnings after the markets close on a Wednesday, in which case, the applicable quarterly blackout period would end at the opening of trading on Friday.

Special Blackout Periods

From time to time, events may occur (or be proposed) that are material to the Company and known by only a limited number of Company personnel. Restricted Persons who are (or may deemed to be) aware of a material nonpublic event and notified by the corporate secretary in writing as being subject to the special blackout period implemented in connection therewith (and their Related Persons) may not engage in transactions in Company securities for so long as the event remains material and nonpublic. **During any special blackout period, you should not disclose to any other person the existence of, or any information related to, the material nonpublic event or the fact that the trading window has been closed, nor should you discuss with anyone the advisability of trading in Company securities.**

Each special blackout period will remain in effect until the corporate secretary has notified the applicable Restricted Person(s) in writing that the special blackout period has ended. If you have any doubt whether a special blackout period has ended, then you should contact the corporate secretary to discuss.

Preclearance Procedures

Restricted Persons are prohibited from engaging in transactions in Company securities without first obtaining preclearance of such transactions from the corporate secretary. The corporate secretary is under no obligation to approve transactions submitted for preclearance and may determine not to permit any transaction that he or she concludes would violate this policy or the federal securities laws. Any such determination by the corporate secretary shall be final and not subject to further review. If you are a Restricted Person, and your request for preclearance of a transaction is denied, then you should not (i) engage in any transaction in Company securities until you receive preclearance from the corporate secretary or (ii) disclose to any other person that your request for preclearance was denied.

If you have any questions about this policy, the federal securities laws, or a proposed transaction, then please contact the corporate secretary to discuss.

Post-Employment Transactions

If your employment or service with the Company ends when you are in possession of material nonpublic information about the Company, you may not engage in transactions in Company securities until such information has become public or is no longer material.

APA Corporation (a Delaware corporation) **Exhibit 21.1**
Listing of Subsidiaries as of December 31, 2025

Exact Name of Subsidiary and Name under which Subsidiary does Business	Jurisdiction of Incorporation or Organization
APA Alaska LLC	Texas
APA DB LLC	Texas
APA Dominican Republic Corporation LDC	Cayman Islands
APA Egypt Investment Corporation LDC	Cayman Islands
APA EIF Holdings, Inc.	Delaware
APA International LLC	Texas
APA International Exploration LDC	Cayman Islands
APA MB LLC	Texas
APA Netherlands Investment B.V.	The Netherlands
APA Suriname Corporation LDC	Cayman Islands
APA Netherlands Investment II B.V.	The Netherlands
APA Suriname 58 Holdings Corporation LDC	Cayman Islands
APA Suriname 58 Corporation LDC	Cayman Islands
APA Netherlands Investment III B.V.	The Netherlands
APA Exploration LDC	Cayman Islands
Peltany S.A.	Uruguay
Callon Petroleum Company	Delaware
Callon Petroleum Operating Company	Delaware
Callon Ventures, LLC	Delaware
Callon Permian II, LLC	Delaware
Callon (Permian) LLC	Delaware
Callon (Permian) Minerals LLC	Delaware
Osprey Royalties LLC	Delaware
Callon (Niobrara) LLC	Delaware
Callon (Utica) LLC	Delaware
Callon Marcellus Holding Inc.	Delaware
Callon (Marcellus) LLC	Delaware
Apache Corporation	Delaware
Alta Vista Oil Corporation	Delaware
Apache Alaska Corporation	Delaware
Apache Crude Oil Marketing, Inc.	Delaware
Apache Deepwater LLC	Texas
Apache Fertilizer Holdings II Corporation LDC	Cayman Islands
Apache Finance Louisiana Corporation	Delaware
Apache Foundation	Minnesota
Apache Finance Pty Limited	Australian Capital Territory
Apache Gathering Company	Delaware
Apache Holdings, Inc.	Delaware
Apache International Employment Inc.	Delaware
Apache Louisiana Holdings LLC	Delaware
Apache Louisiana Minerals LLC	Delaware
Apache Marketing, Inc.	Delaware
Apache Midstream LLC	Delaware
Apache Natural Gas Transportation Fuels LLC	Delaware
Apache North America LLC	Delaware
Apache Oil Corporation	Texas
Apache Overseas LLC	Delaware
Apache Asia Pacific Corporation LDC	Cayman Islands
Apache International Finance	Cayman Islands
Apache International Finance II	Cayman Islands
Apache Egypt GP Corporation LDC	Cayman Islands

APA Corporation (a Delaware corporation) **Exhibit 21.1**
Listing of Subsidiaries as of December 31, 2025

Exact Name of Subsidiary and Name under which Subsidiary does Business	Jurisdiction of Incorporation or Organization
Apache Egypt Holdings III Corporation LDC	Cayman Islands
Apache Egypt Holdings II Corporation LDC	Cayman Islands
Apache Abu Gharadig Corporation LDC	Cayman Islands
Apache East Bahariya Corporation LDC	Cayman Islands
Apache El Diyur Corporation LDC	Cayman Islands
Apache Faiyum Corporation LDC	Cayman Islands
Apache Khalda Corporation LDC	Cayman Islands
Apache Egypt Midstream Holdings I LDC	Cayman Islands
Apache Khalda II Corporation LDC	Cayman Islands
Apache Matruh Corporation LDC	Cayman Islands
Apache Mediterranean Corporation LDC	Cayman Islands
Apache North Bahariya Corporation LDC	Cayman Islands
Apache North El Diyur Corporation LDC	Cayman Islands
Apache North Tarek Corporation LDC	Cayman Islands
Apache Qarun Corporation LDC	Cayman Islands
Apache Qarun Exploration Company LDC	Cayman Islands
Apache Shushan Corporation LDC	Cayman Islands
Apache South Umbarka Corporation LDC	Cayman Islands
Apache Umbarka Corporation LDC	Cayman Islands
Apache West Kalabsha Corporation LDC	Cayman Islands
Apache West Kanays Corporation LDC	Cayman Islands
Apache UK Consolidated Holdings Corporation LDC	Cayman Islands
Apache UK Corporation LDC	Cayman Islands
Apache International Corporation LDC	Cayman Islands
Apache North Sea Limited	England and Wales
Apache UK Pension Trustee Ltd.	England and Wales
Apache North Sea Production Limited	England and Wales
Apache UK Investment Limited	England and Wales
Apache Beryl I Limited	Cayman Islands
Apache EMEA Corporation LDC	Cayman Islands
Apache Exploration LDC	Cayman Islands
Apache Fertilizer Holdings Corporation LDC	Cayman Islands
Apache Latin America II Corporation LDC	Cayman Islands
Apache Ravensworth Corporation LDC	Cayman Islands
Apache Shady Lane Ranch Inc.	Delaware
Apache Shelf Exploration LLC	Texas
Apache Shelf, Inc.	Delaware
BLPL Holdings LLC	Delaware
Clear Creek Hunting Preserve, Inc.	Wyoming
Cordillera Energy Partners III, LLC	Colorado
Cottonwood Aviation, Inc.	Delaware
CV Energy Corporation	Delaware
CV Production LLC	Texas
DEK Energy LLC	Delaware
Apache Finance Canada LLC	Delaware
Apache Permian Basin Corporation	Delaware
Apache Permian Exploration and Production LLC	Delaware
LeaCo New Mexico Exploration and Production LLC	Delaware
Permian Basin Joint Venture LLC	Delaware
ZPZ Delaware I LLC	Delaware
Apache Canada Management LLC	Delaware

APA Corporation (a Delaware corporation) **Exhibit 21.1**
Listing of Subsidiaries as of December 31, 2025

Exact Name of Subsidiary and Name under which Subsidiary does Business	Jurisdiction of Incorporation or Organization
Apache Canada Holdings LLC	Delaware
Apache Canada Management II LLC	Delaware
Apache Finance Canada III LLC	Delaware
Apache Finance Canada IV LLC	Delaware
Stallion Canada Holdings LLC	Delaware
Edge Petroleum Exploration Company	Delaware
Phoenix Exploration Resources, Ltd.	Delaware
Texas International Company	Delaware
Texas and New Mexico Exploration LLC	Delaware
ZPZ Acquisitions, Inc.	Delaware
ZPZ Delaware II LLC	Delaware
Phoenix Exploration Louisiana C LLC (75%)	Delaware
ZPZ Delaware III LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

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

(1) Registration Statements (Form S-3 Nos. 333-278448 and 333-279038) of APA Corporation and in the related Prospectuses,

(2) Registration Statement (Form S-4/A No. 333-276797) of APA Corporation, including the post-effective amendment thereto on Form S-8, and in the related Prospectuses, and

(3) Registration Statement (Form S-8 No. 333-253754) of APA Corporation and in the related Prospectuses;

of our reports dated February 26, 2026, with respect to the consolidated financial statements of APA Corporation and subsidiaries and the effectiveness of internal control over financial reporting of APA Corporation and subsidiaries, included in this Annual Report (Form 10-K) of APA Corporation for the year ended December 31, 2025.

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2026

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.2

Consent of Ryder Scott Company, L.P.

As independent petroleum engineers, we hereby consent to the incorporation by reference in this Form 10-K of APA Corporation to our Firm's name and our Firm's review of the proved oil and gas reserve quantities of APA Corporation as of December 31, 2025, to the incorporation by reference of our Firm's name and review into APA Corporation's previously filed Registration Statements on Form S-3 (Nos. 333-278448 and 333-279038), on Form S-4/A (No. 333-276797), including the post effective amendment thereto on Form S-8, and on Form S-8 (No. 333-253754), and to the inclusion of our report, dated January 22, 2026, as an exhibit to this Form 10-K filed with the Securities and Exchange Commission.

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas
February 26, 2026

SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
555 17TH STREET, SUITE 985 DENVER, COLORADO 80202 TEL (303) 339-8110

EXHIBIT 31.1

CERTIFICATIONS

I, John J. Christmann IV, certify that:

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

Date: February 26, 2026

/s/ John J. Christmann IV

John J. Christmann IV
Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATIONS

I, Ben C. Rodgers, certify that:

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

Date: February 26, 2026

/s/ Ben C. Rodgers

Ben C. Rodgers
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

APA CORPORATION

Certification of Principal Executive Officer
and Principal Financial Officer

I, John J. Christmann IV, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the Annual Report on Form 10-K of APA Corporation for the period ending December 31, 2025, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of APA Corporation.

Date: February 26, 2026

/s/ John J. Christmann IV

By: John J. Christmann IV
Title: Chief Executive Officer
(principal executive officer)

I, Ben C. Rodgers, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the Annual Report on Form 10-K of APA Corporation for the period ending December 31, 2025, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of APA Corporation.

Date: February 26, 2026

/s/ Ben C. Rodgers

By: Ben C. Rodgers
Title: Executive Vice President and Chief Financial Officer
(principal financial officer)

APA CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

and

Derived Through Certain Production Sharing Contracts

SEC Parameters

As of

December 31, 2025

/s/ Ali A. Porbandarwala
Ali A. Porbandarwala, P.E.
TBPELS License No. 107652
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 22, 2026

APA Corporation
2000 W. Sam Houston Pkwy S #200
Houston, Texas 77042

Ladies and Gentlemen:

At the request of APA Corporation (Apache), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2025 prepared by Apache's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 1, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on January 13, 2026 and presented herein, was prepared for public disclosure by Apache in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Apache's estimated net reserves attributable to the leasehold and royalty interests and derived through certain production sharing contracts in certain properties owned by Apache and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2025. The properties reviewed by Ryder Scott incorporate Apache's reserves determinations and are attributable to the interests of Apache Corporation (U.S.A), Apache Egypt Companies (Egypt), APA Suriname 58 Corporation LDC and Apache North Sea Limited (United Kingdom).

The properties reviewed by Ryder Scott account for a portion of Apache's total net proved liquid hydrocarbon and gas reserves as of December 31, 2025. Based on the estimates of total net proved reserves prepared by Apache, the reserves audit conducted by Ryder Scott addresses approximately 81.5 percent of the total proved net reserves of Apache on a barrel of oil equivalent, BOE basis as of December 31, 2025.

The properties reviewed by Ryder Scott account for a portion of Apache's total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2025. Based on the reserves and income projections prepared by Apache, the audit conducted by Ryder Scott addresses approximately 86.8 percent of the total proved discounted future net income at 10%.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Apache, it is our opinion that the overall procedures and methodologies utilized by Apache in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Apache are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Apache has informed us that in the preparation of their reserves and income projections, as of December 31, 2025, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Apache attributable to Apache's interest and entitlement in properties that we reviewed and the reserves of properties that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Proved Reserves
Certain Leasehold and Royalty Interests and
Derived Through Certain Production Sharing Contracts of
APA Corporation (Total All Countries)
As of December 31, 2025

	% Crude Oil & Condensate Reserves Reviewed	% Natural Gas Liquids Reserves Reviewed	% Gas Reserves Reviewed	Reviewed by Ryder Scott			Not Reviewed			Total		
				Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF
Developed	82.2	88.0	86.2	251,681	159,800	1,275,739	54,505	21,789	203,733	306,186	181,589	1,479,471
Undeveloped	76.1	69.5	69.8	154,010	40,636	255,521	48,436	17,802	110,359	202,446	58,437	365,880
Total Proved	79.8	83.5	83.0	405,691	200,436	1,531,260	102,941	39,591	314,092	508,632	240,027	1,845,351

SEC PARAMETERS
Estimated Net Proved Reserves
Certain Leasehold and Royalty Interests and
Derived Through Certain Production Sharing Contracts of
APA Corporation (Summary by Country)
As of December 31, 2025

				Reviewed by Ryder Scott			Not Reviewed			Total		
	% Crude Oil & Condensate Reserves Reviewed	% Natural Gas Liquids Reserves Reviewed	% Gas Reserves Reviewed	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF
USA												
Developed	84.0	88.1	86.8	153,117	159,129	950,308	29,183	21,561	145,087	182,300	180,690	1,095,395
Undeveloped	61.7	69.5	70.7	74,677	40,636	238,963	46,403	17,802	99,137	121,079	58,437	338,100
Total Proved	75.1	83.5	83.0	227,793	199,764	1,189,272	75,586	39,363	244,224	303,379	239,128	1,433,495
Egypt												
Developed	78.0	N/A	85.5	79,394	0	317,401	22,356	0	53,934	101,750	0	371,335
Undeveloped	73.2	N/A	59.6	5,544	0	16,557	2,033	0	11,223	7,577	0	27,780
Total Proved	77.7	N/A	83.7	84,938	0	333,959	24,389	0	65,156	109,327	0	399,115
Suriname												
Developed	N/A	N/A	N/A	0	0	0	0	0	0	0	0	0
Undeveloped	100.0	N/A	N/A	73,790	0	0	0	0	0	73,790	0	0
Total Proved	100.0	N/A	N/A	73,790	0	0	0	0	0	73,790	0	0
United Kingdom												
Developed	86.6	74.7	63.0	19,170	671	8,029	2,966	228	4,712	22,136	899	12,741
Undeveloped	N/A	N/A	N/A	0	0	0	0	0	0	0	0	0
Total Proved	86.6	74.7	63.0	19,170	671	8,029	2,966	228	4,712	22,136	899	12,741

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousand of barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The reference above to barrel of oil equivalent (BOE), is the method wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed reserves included herein consist of the producing, shut-in and behind pipe status categories.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal

categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Apache's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered

from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Apache, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through November 2025, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Apache or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 10 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

All of the proved developed non-producing and the undeveloped status categories that we reviewed were estimated by the volumetric method or analogy. The volumetric analysis utilized pertinent well and seismic data, reports and other data furnished to Ryder Scott by Apache for our review or which we have obtained from public data sources that were available through November, 2025. The data utilized from the analogues in conjunction with well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Apache relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon benchmark prices furnished by Apache for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual

arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2025 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices, provided by Apache, appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used by Apache for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements. In cases where there are numerous contracts or price references within the same geographic area, the benchmark price is represented by the unweighted arithmetic average of the initial 12-month average first-day-of-the-month benchmark prices used.

The product prices that were actually used by Apache to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache.

The table below summarizes Apache's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Apache's "average realized prices." The average realized prices shown in the table below were determined from Apache's estimate of the total future gross revenue before production taxes for the properties reviewed by us and Apache's estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the following table is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$65.34/Bbl	$65.28/Bbl
	NGLs	Mt. Belvieu Non-Tet Propane	$31.79/Bbl	$22.03/Bbl
	Gas	Henry Hub	$3.39/MMBTU	$0.58/Mcf
Egypt	Oil/Condensate	Brent	$69.51/Bbl	$69.88/Bbl
	NGLs	Brent	$69.51/Bbl	N/A
	Gas	Contracts	Contract	$3.93/Mcf
Suriname	Oil/Condensate	Brent	$69.51/Bbl	$68.21/Bbl
	NGLs	Brent	$69.51/Bbl	N/A
	Gas	Contracts	Contract	N/A
United Kingdom	Oil/Condensate	Brent	$69.51/Bbl	$71.08/Bbl
	NGLs	Brent	$69.51/Bbl	$45.49/Bbl
	Gas	UK National Balancing Point (NBP)	$11.76/MMBTU	$12.02/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Apache's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Apache are based on the operating expense reports of Apache and include only those costs directly applicable to the leases, contract areas, or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases, contract areas, and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases, contract areas, and wells under terms of operating agreements. Other costs include transportation and/or processing fees as deductions. The operating costs furnished by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Apache are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache. The estimated net cost of abandonment after salvage was included by Apache for properties where abandonment costs net of salvage were material. Apache's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Apache's plans to develop these reserves as of December 31, 2025. The implementation of Apache's development plans as presented to us is subject to the approval process adopted by Apache's management. As the result of our inquiries during the course of our review, Apache has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Apache's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Apache. Apache has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Apache has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2025, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Apache were held constant throughout the life of the properties.

Apache's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Apache to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Apache. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Apache's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal right to produce or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain.

The proved reserves for the properties located in Egypt and Suriname are subject to the contractual fiscal terms contained in production sharing contracts. For these properties, Ryder Scott audited the gross economic inputs used by Apache in the economic models for Egypt and Suriname through a comparison of Apache's and Ryder Scott's gross economic volumes. Apache's gross economic volumes were then used as input to the economic models to generate the net interests used to determine the net reserves summarized in this report. Ryder Scott reviewed the fiscal terms of such contracts and discussed with Apache the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Apache's representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Apache operates or has interests. Apache's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, contract terms, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms of various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the quantities as estimated by Apache.

The estimates of proved reserves presented herein were based upon a review of the properties in which Apache owns and derives an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Apache for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Apache are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner.

We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Apache has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Apache's forecast of future proved production, we have relied upon data furnished by Apache with respect to property interests owned or derived, production and well tests from examined wells, normal direct costs of operating the wells, leases or contract areas, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Apache. We consider the factual data furnished to us by Apache to be appropriate and sufficient for the purpose of our review of Apache's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Apache and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Apache, it is our opinion that the overall procedures and methodologies utilized by Apache in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Apache are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Apache in their estimate of proved reserves to be effective and in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Apache's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Apache's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Apache when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned or derived by Apache.

Other Properties

Other properties, as used herein, are those properties of Apache which we did not review. The proved net reserves attributable to the other properties account for approximately 18.5 percent of the total proved net liquid hydrocarbon and gas reserves of Apache on a barrel of oil equivalent, BOE basis, based on estimates prepared by Apache as of December 31, 2025. The other properties represent approximately 13.2 percent of the total proved discounted future net income at 10% based on the unescalated pricing policy of the SEC as taken from reserves and income projections prepared by Apache.

The same technical personnel of Apache were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Apache. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by APA Corporation.

Apache makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Apache has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3, Form S-4, and Form S-8 of Apache, of the references to our name, as well as to the references to our third party report for Apache, which appears in the December 31, 2025 annual report on Form 10-K of Apache. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Apache.

We have provided Apache with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Apache and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.
TBPELS License No. 107652
Managing Senior Vice President **[SEAL]**

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Ali A. Porbandarwala was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Porbandarwala, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2008, is a Managing Senior Vice President and a member of the Board of Directors. He is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Porbandarwala served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Porbandarwala's geographic and job specific experience, please refer to the Ryder Scott website at www.ryderscott.com/Employees.

Mr. Porbandarwala earned a Bachelor of Science degree in Chemical Engineering from The University of Kansas in 2001 and a Master's in Business Administration from The University of Texas at Austin in 2007 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and a member of the Society of Petroleum Evaluation Engineers. Mr. Porbandarwala also served as the Chairman of the annual Ryder Scott Reserves Conference for four years.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Porbandarwala fulfills. As part of his 2025 continuing education hours, Mr. Porbandarwala attended over 26 hours of formalized training including the 2025 Ryder Scott Reserves Conference and various other professional society presentations specifically relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Porbandarwala has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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

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

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

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

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

> ***Developed Producing Reserves***
> *Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.*

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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

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

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

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