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, 2023

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.)

One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400
(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, 2023	$	10,499,243,068
Number of shares of registrant’s common stock outstanding as of January 31, 2024		301,818,820

Documents Incorporated By Reference

Portions of the registrant’s definitive proxy statement relating to the registrant’s 2024 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, plans and objectives of management for future operations and capital returns framework, the anticipated benefits of the proposed merger (the merger) between the Company and Callon Petroleum Company (Callon), the anticipated impact of the merger on the combined company's business and future financial and operating results, the anticipated financial and operational impact and timing of the expected synergies from the merger, and the anticipated closing date for the merger, 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, 2023, 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," "believe," "continue," "seek," "guidance," "goal," "might," "outlook," "possibly," "potential," "prospect," "should," "would," or similar terminology, 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, including as a result of any epidemics or pandemics, such as the coronavirus disease (COVID-19) pandemic and any related variants;
- 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 the Russian war in Ukraine, the armed conflict in Israel and Gaza, 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;
- currency exchange rates;
- weather conditions;
- inflation rates;
- the impact of changes in tax legislation;
- 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;
- the Company's performance on environmental, social, and governance measures;
- cyberattacks and terrorism;
- the Company's ability to access the capital markets;
- 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;
- the risk that the Company’s or Callon’s stockholders may not approve the merger;
- uncertainties as to the timing to consummate the merger, including the possibility that the merger is delayed or does not occur;
- the risk that the Company or Callon may be unable to obtain governmental and regulatory approvals required for the merger, or that required governmental and regulatory approvals may delay the merger or result in the imposition of conditions that could reduce the anticipated benefits from the merger or cause the parties to abandon the merger;
- the risk that a condition to closing of the merger may not be satisfied in a timely manner or at all;
- the occurrence of events that may give rise to a right of one or both of the parties to terminate the merger agreement, including under circumstances that might require the Company or Callon to pay the other party a termination fee;
- the risk that the businesses will not be integrated successfully following the merger;
- the risk that the cost savings, synergies, and growth from the merger may not be fully realized or may take longer to realize than expected;
- the diversion of management time on merger-related issues;
- the risks related to the Company and Callon being restricted in the operation of their respective businesses while the merger is pending;
- negative effects of the announcement of the potential completion of the merger on the market price of the Company’s common stock, the Company’s financial performance, and on relationships with the Company's customers, providers, vendors, competitors, management, and other employees; and
- 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 the 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 consolidated subsidiaries that explore for, develop, and produce natural gas, crude oil, and NGLs. The Company's upstream 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 exploration and appraisal operations ongoing in Suriname, as well as interests in Uruguay and other international locations that may, over time, result in reportable discoveries and development opportunities. Prior to the BCP Business Combination (as defined below), the Company's midstream business was operated by Altus Midstream Company (ALTM) through its subsidiary Altus Midstream LP (collectively, Altus).

On March 1, 2021, Apache Corporation consummated a holding company reorganization (the Holding Company Reorganization), pursuant to which Apache Corporation became a direct, wholly owned subsidiary of APA Corporation, and all of Apache Corporation's outstanding shares automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to Apache Corporation pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache Corporation as the public company trading on the Nasdaq Global Select Market (Nasdaq) under the ticker symbol "APA." The Holding Company Reorganization modernized the Company's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have subsidiaries operating around the globe. As a holding company, APA has no business operations of its own, and its only significant assets are the outstanding equity interests of its subsidiaries. As such, most properties referred to herein are held by subsidiaries of APA.

The Company's common stock, par value $0.625 per share, is listed on the Nasdaq. Through the Company's website, www.apacorp.com, you can access, free of charge, electronic copies of the charters of the committees of the Company's board of directors (Board of Directors), other documents related to corporate governance (including the Code of Business Conduct and Ethics and APA's Corporate Governance Principles), and documents the Company files with the SEC, including the Company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K, as well as any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act. Included in the Company's annual and quarterly reports are the certifications of its principal executive officer and its principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after the Company files such material with, or furnishes it to, the SEC. You may also request printed copies of the Company's corporate charter, bylaws, committee charters, or other governance documents free of charge by writing to the Company's corporate secretary at the address on the cover of this Annual Report on Form 10-K. The Company's reports filed with the SEC are made available on its website at www.sec.gov. From time to time, the Company also posts announcements, updates, and investor information on its website in addition to copies of all recent press releases. 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.

BUSINESS STRATEGY

APA maintains a diversified asset portfolio, including conventional and unconventional, onshore and offshore, oil and natural gas exploration and production interests. In the U.S., operations are primarily focused in the Permian Basin of West Texas and Eastern New Mexico, with additional operations located in the Eagle Ford shale and Austin Chalk areas of Southeast Texas, offshore in the Gulf of Mexico, and along the Gulf Coast. The Company also commenced an exploration program in Alaska during the fourth quarter of 2023. Internationally, the Company has conventional onshore assets in Egypt's Western Desert, offshore assets on the U.K.'s Continental Shelf, and an offshore appraisal and exploration program in Suriname.

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. Management actively reviews certain non-strategic assets for opportunities, which include potential monetization of legacy properties and other non-core leasehold positions.

In late 2021, the Company refreshed the economic foundation for its business in Egypt with the ratification of a merged concession agreement (MCA) with the Egyptian Ministry of Petroleum and the Egyptian General Petroleum Corporation (EGPC). The MCA consolidated the majority of the Company's gross acreage and production in Egypt under one concession agreement and refreshed existing development and exploration lease terms.

On February 22, 2022, ALTM closed on a transaction to combine with privately owned BCP Raptor Holdco LP (BCP) in an all-stock transaction. Upon closing the transaction, the combined entity was renamed Kinetik Holdings Inc. (Kinetik), and APA's ownership in ALTM was reduced from approximately 79 percent to approximately 20 percent. Upon closing the transaction, the Company deconsolidated ALTM. The deconsolidation provides a number of benefits to APA shareholders, including simplification of the Company's financial reporting and enhanced comparability with its upstream-only peers, while maintaining a noncontrolling interest in future growth opportunities of Kinetik. Subsequent sales of the Company's shares of Kinetik Class A Common Stock (Kinetik Shares) have reduced APA's ownership in Kinetik to approximately 9 percent.

On January 3, 2024, APA and Callon Petroleum Company (Callon) entered into a definitive agreement, pursuant to which APA will acquire Callon in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's net debt. In this all-stock transaction, each eligible outstanding share of Callon common stock will be exchanged for 1.0425 shares of APA common stock. After closing, existing APA shareholders are expected to own approximately 81 percent of the combined company, and existing Callon shareholders are expected to own approximately 19 percent of the combined company. This transaction complements and enhances APA's asset base in the Permian Basin and adds to APA's inventory of high quality, short-cycle opportunities. In addition, Callon's assets provide additional scale to APA's operations across the Permian Basin.

Uncertainties in the global supply chain and financial markets, including the impact of inflation, and rising interest rates, and actions taken by foreign oil and gas producing nations, including OPEC+, continue to impact oil supply and demand and contribute to commodity price volatility. Despite these uncertainties, the Company remains committed to its longer-term objectives: (1) to maintain a balanced asset portfolio, including advancement of activities offshore Suriname; (2) to invest for long-term returns over production growth; and (3) to budget conservatively to generate 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. The Company continues to aggressively manage its cost structure regardless of the oil price environment and closely monitors hydrocarbon pricing fundamentals to reallocate capital as part of its ongoing planning process.

For a more in-depth discussion of the Company's 2023 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 operations and activities for the Company’s upstream exploration and production properties, by geographic region.

UPSTREAM EXPLORATION AND PRODUCTION

Operating Areas

APA’s upstream 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 exploration and appraisal operations ongoing in Suriname, as well as interests in Uruguay 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 2023 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	79.3	54 %	$ 3,018	566	70 %	127	127
Egypt[1]	52.3	35 %	3,029	171	21 %	123	91
North Sea[2]	16.2	11 %	1,338	70	9 %	2	2
Other International	—	—	—	—	—	2	—
Total	147.8	100 %	$ 7,385	807	100 %	254	220

(1) The Company’s operations in Egypt, excluding the impacts of a one-third noncontrolling interest, contributed 27 percent of 2023 production and accounted for 15 percent of year-end 2023 estimated proved reserves.

(2) Sales volumes from the Company’s North Sea assets for 2023 were 16.6 MMboe. Sales volumes may vary from production volumes as a result of the timing of liftings.

United States

In 2023, the Company’s U.S. upstream oil and gas operations contributed approximately 54 percent of production, 41 percent of oil and gas revenues, and 70 percent of estimated year-end proved reserves. APA has access to significant liquid hydrocarbons across its 3.7 million gross acres (1.8 million net acres) in the U.S., 76 percent of which are undeveloped.

The Company’s U.S. assets are primarily located in the Permian Basin in West Texas and New Mexico, including the Permian sub-basins: Midland Basin, Central Basin Platform/Northwest Shelf, and Delaware Basin. Examples of shale plays being developed within these sub-basins include the Woodford, Barnett, Pennsylvanian, Cline, Wolfcamp, Bone Spring, and Spraberry. The Company is one of the largest operators in the Permian Basin, operating approximately 5,000 gross oil and gas wells across its acreage, with additional interests in less than 3,000 non-operated wells. APA also has operations located in the Eagle Ford shale and Austin Chalk areas of Southeast Texas, offshore in the Gulf of Mexico, and along the Gulf Coast in South Texas and Louisiana.

Highlights of the Company’s operations in the U.S. include:

- *Southern Midland Basin* APA holds approximately 786,000 gross acres (450,000 net acres) in the Southern Midland Basin and the Eagle Ford shale and Austin Chalk areas of southeast Texas. During 2023, the Company primarily targeted oil plays in the Wolfcamp and Spraberry formations, drilling 69 gross development wells in this basin with a 100 percent success rate.
- *Delaware Basin* APA holds approximately 233,000 gross acres (135,000 net acres) in the Delaware Basin, including opportunities in the Bone Spring and other formations of Eastern New Mexico and bordering West Texas, and the Alpine High play in the southern portion of the Permian Basin, primarily in Reeves County, Texas. During 2023, the Company drilled 57 gross development wells in this basin with a 100 percent success rate.

- *Legacy Assets* APA holds approximately 2.4 million gross acres (1.1 million net acres) in legacy properties, of which approximately 577,000 gross acres are in the offshore waters of the Gulf of Mexico. 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.
- *New Venture Assets* APA separately has undeveloped acreage positions across several states, where it intends to pursue exploration interests and potential development opportunities over time. During the fourth quarter of 2023, the Company commenced an exploration program in Alaska, where it anticipates drilling three exploration wells in the first half of 2024.

The Company is committed to maintaining a safe, steady, and efficient level of activity as part of its three-year capital investment program. For 2024, 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. 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. In addition, to satisfy a delivery commitment that began in 2023, the Company purchases third party natural gas to sell and deliver to a U.S. LNG export facility. 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 161 Bcf of natural gas per year for the period from 2024 through 2029, an average of 49 Bcf of natural gas per year for the period from 2030 through 2037, and an average of 4.9 MMbbls of crude oil per year for the period from 2024 through 2025, in each case, at variable, domestic and/or international, market-based pricing.

APA currently expects to fulfill its delivery commitments with production from its proved reserves, production from continued development, and/or third-party purchases. 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

In 2023, international assets contributed 46 percent of APA's production and 59 percent of its oil and gas revenues. Approximately 30 percent of estimated proved reserves at year-end 2023 were located outside the U.S.

APA has two international locations with ongoing development and 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.

The Company also has an active offshore exploration program and appraisal operations ongoing in Suriname, and interests in Uruguay and other international locations that may, over time, result in reportable discoveries and development opportunities.

Egypt APA has decades of exploration, development and operations experience in Egypt and is one of the largest acreage holders in Egypt's Western Desert. At year-end 2023, the Company held 5.3 million gross acres in six separate concessions. The Company's acreage is primarily held under one concession agreement that resulted from the ratification of a new MCA with the Egyptian Ministry of Petroleum and EGPC. The MCA, which has an effective date of April 1, 2021, 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. Development leases within concessions currently have expiration dates ranging from 1 to 20 years, with extensions possible for additional commercial discoveries or on a negotiated basis. Approximately 67 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 35 percent of 2023 production and 21 percent of 2023 year-end estimated proved reserves. Excluding the impacts of the noncontrolling interest, Egypt contributed 27 percent of 2023 production and 15 percent of 2023 year-end estimated proved reserves.

In 2023, the Company drilled 75 gross development and 48 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.

North Sea The Company has interests in approximately 292,000 gross acres in the U.K. North Sea. These assets contributed 11 percent of the Company's 2023 production and approximately 9 percent of year-end 2023 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. During the second quarter of 2023, as part of the Company's focus on capital allocation to optimize investment returns, it suspended all new drilling activity in the North Sea. The Company's investment program there is now directed toward safety, base production management, and asset maintenance and integrity.

International Marketing The Company's natural gas production in Egypt is sold to EGPC primarily under an industry-pricing formula, a sliding scale based on Dated Brent crude oil with a minimum of $1.50 per MMBtu and a maximum of $2.65 per MMBtu, plus an upward adjustment for liquids content. 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 Exploration

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 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 Block 58 as the operator. Key terms of the 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.

During 2023, the Company and TotalEnergies announced the launch of development studies for a large oil project in Block 58. Successful appraisal of two key oil discoveries, with the drilling and testing of two wells at Sapakara South and three wells at Krabdagu, confirmed combined recoverable resources of an estimated 700 million barrels of oil for the two fields. These fields, located in water depths between 100 and 1,000 meters, are expected to be produced through a system of subsea wells connected to a floating production, storage and offloading unit located 150 kilometers off the Suriname coast, with an oil production capacity of 200,000 b/d. Detailed engineering studies are underway, and a final investment decision is expected by year-end 2024, with a first production target in 2028. No additional drilling is anticipated on Block 58 through the end of 2024.

The Company is also the operator of Block 53 offshore Suriname and holds a 45 percent working interest in the block. Exploration and evaluation of the area is ongoing. During 2023, the Company was granted an extension to retain approximately 13,000 net undeveloped acres for its operated Baja discovery area, allowing the remaining net undeveloped acres to expire in Block 53 as of the end of 2023.

During 2023, the Company signed a production sharing contract for Block 6 offshore Uruguay covering approximately four million net undeveloped acres and expects to commence exploration activities in 2024. In February 2024, the Company also signed a production sharing contract for Block 4 offshore Uruguay.

In December 2023, the Company suspended further exploration activities in its approximately 630,000 net undeveloped acres offshore the Dominican Republic. The Company has elected to voluntarily relinquish its net acreage holdings and anticipates completion of its withdrawal in early 2024. The Company continues to assess, contract, and potentially explore undeveloped acreage positions in other international locations.

Drilling Statistics

Worldwide in 2023, APA drilled or participated in drilling 254 gross wells, with 220 wells (87 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 2023, at year-end 2023, a number of wells had not yet reached completion: 81 gross (74.2 net) in the U.S., 49 gross (49.0 net) in Egypt, 3 gross (2.5 net) in the North Sea, and 1 gross (0.5 net) in Suriname.

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	Total	Productive	Dry	Total
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
2022									
United States	—	—	—	40.7	—	40.7	40.7	—	40.7
Egypt	15.0	14.5	29.5	64.4	—	64.4	79.4	14.5	93.9
North Sea	1.0	—	1.0	1.0	—	1.0	2.0	—	2.0
Other International	—	2.1	2.1	—	—	—	—	2.1	2.1
Total	16.0	16.6	32.6	106.1	—	106.1	122.1	16.6	138.7
2021									
United States	—	—	—	67.9	—	67.9	67.9	—	67.9
Egypt	10.0	14.0	24.0	28.5	1.0	29.5	38.5	15.0	53.5
North Sea	0.6	0.5	1.1	1.8	0.5	2.3	2.4	1.0	3.4
Other International	—	1.3	1.3	—	—	—	—	1.3	1.3
Total	10.6	15.8	26.4	98.2	1.5	99.7	108.8	17.3	126.1

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, 2023, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	7,871	4,603	1,044	740	8,915	5,343
Egypt	1,084	1,047	108	105	1,192	1,152
North Sea	148	106	10	6	158	112
Total	9,103	5,756	1,162	851	10,265	6,607
Domestic	7,871	4,603	1,044	740	8,915	5,343
Foreign	1,232	1,153	118	111	1,350	1,264
Total	9,103	5,756	1,162	851	10,265	6,607

Gross natural gas and crude oil wells included 457 wells with multiple completions.

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)
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
2022							
United States	25.7	22.8	172.8	$ 10.73	$ 95.68	$ 33.41	$ 5.31
Egypt[1]	31.1	0.1	130.1	10.37	101.25	76.80	2.85
North Sea[2]	11.9	0.4	12.8	30.07	100.87	67.07	23.36
Total	68.7	23.3	315.7	12.59	99.11	34.51	4.98
2021							
United States	27.4	24.2	192.5	$ 8.37	$ 67.37	$ 27.85	$ 3.92
Egypt[1]	25.7	0.2	96.2	11.48	70.33	48.84	2.81
North Sea[2]	13.2	0.4	14.1	26.12	69.67	54.30	12.96
Total	66.3	24.8	302.8	11.31	68.97	28.48	3.99

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

(2) Sales volumes from the Company's North Sea assets for 2023, 2022, and 2021 were 16.6 MMboe, 14.9 MMboe, and 16.1 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, 2023:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(In thousands)			
United States	2,800	1,286	886	546
Egypt	3,567	3,567	1,728	1,681
North Sea	133	116	159	123
Other International	6,177	5,440	—	—
Total	12,677	10,409	2,773	2,350

As of December 31, 2023, the Company held approximately 117,000 net undeveloped acres that are scheduled to expire by year-end 2024 if production is not established or the Company takes no action to extend the terms. Nearly all of the Company's acreage expiring in 2024 is offshore the U.K. in the North Sea. The Company also held approximately 16,000 and 724,000 net undeveloped acres set to expire by year-end 2025 and 2026, respectively. Exploration concessions covering the Company's Egyptian acreage were extended in 2021 upon ratification of the MCA with the EGPC, and no acreage is scheduled to expire before 2026. The Company will continue to pursue acreage extensions and access to new concessions in areas in which it believes exploration opportunities exist. The Company strives to extend the terms of many of these licenses and concession areas through operational or administrative actions but cannot assure that such extensions can be achieved on an economic basis or otherwise on terms agreeable to both the Company and third parties, including governments. No oil and gas reserves were recorded on this undeveloped acreage set to expire.

As of December 31, 2023, approximately 88 percent of U.S. net undeveloped acreage was held by production or owned as undeveloped mineral rights.

The Company held approximately 5.4 million net undeveloped acres as of December 31, 2023, in international locations separate from positions held in its established U.K. and Egypt locations. Exploration interests include Block 53 and Block 58 offshore Suriname, Block 6 offshore Uruguay, and offshore the Dominican Republic.

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 2026 assuming no further actions are taken to extend. Separately during 2023, the Company was granted an extension to retain approximately 13,000 net undeveloped acres for its operated Baja discovery area, allowing the remaining net undeveloped acres to expire in Block 53 as of the end of 2023.

During 2023, the Company also signed a production sharing contract for Block 6 offshore Uruguay covering approximately four million net undeveloped acres and expects to commence exploration activities in 2024. In February of 2024, the Company also signed a production sharing contract for Block 4 offshore Uruguay.

In December 2023, the Company suspended further exploration activities in its approximately 630,000 net undeveloped acres offshore the Dominican Republic. The Company has elected to voluntarily relinquish its net acreage holdings and anticipates completion of its withdrawal in early 2024.

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, 2023, based on average commodity prices in effect on the first day of each month in 2023, 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	180	153	1,004	500
Egypt[1]	102	—	377	165
North Sea	61	2	47	70
Total	343	155	1,428	735
Proved Undeveloped:				
United States	31	18	99	66
Egypt[1]	5	—	3	6
North Sea	—	—	—	—
Total	36	18	102	72
Total Proved	379	173	1,530	807

(1) Includes total proved developed and total proved undeveloped reserves of 55 MMboe and 2 MMboe, respectively, attributable to a one-third noncontrolling interest in Egypt.

As of December 31, 2023, the Company had total estimated proved reserves of 379 MMbbls of crude oil, 173 MMbbls of NGLs, and 1.5 Tcf of natural gas. Combined, these total estimated proved reserves are the volume equivalent of 807 million boe, of which liquids represent approximately 68 percent. As of December 31, 2023, the Company's proved developed reserves totaled 735 MMboe and estimated proved undeveloped (PUD) reserves totaled 72 MMboe, or approximately 9 percent of worldwide total proved reserves. APA has elected not to disclose probable or possible reserves in this filing. The Company had no fields that contained 15 percent or more of its total proved reserves for the year ended December 31, 2023. The Company had one field that contained 15 percent or more of its total proved reserves for each of the years ended December 31, 2022 and 2021.

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, offset by engineering and performance upward revisions of 37 MMboe.

The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2023, 2022, and 2021, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 18—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 72 MMboe as of December 31, 2023, decreased by 16 MMboe from 88 MMboe of PUD reserves reported at year end 2022. During 2023, the Company converted 39 MMboe of PUD reserves to proved developed reserves through development drilling activity. In the U.S., the Company converted 37 MMboe, with the remaining 2 MMboe in its international areas. The Company had no sales nor purchases in place related to PUD reserves during 2023. The Company added 81 MMboe of new PUD reserves through extensions and discoveries. Downward revisions totaled 58 MMboe, comprising 13 MMboe associated with engineering and interest revisions, 16 MMboe associated with revised development plans, and 29 MMboe associated with product prices.

During 2023, a total of approximately $377 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 2023, the Company spent approximately $323 million on PUD reserve development activity in the U.S. and $54 million in the international areas. As of December 31, 2023, 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 centralized group of experienced reservoir engineers that is independent of the operating groups. These engineers 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. Reserves are reviewed internally with senior management and presented to APA's Board of Directors in summary form on a quarterly basis. 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.

APA's Executive Vice President of Development is the person primarily responsible for overseeing the preparation of the Company's internal reserve estimates and for coordinating any reserves audits conducted by a third-party engineering firm. He has Bachelor of Science and Master of Science degrees in Petroleum Engineering and over 30 years of experience in the energy industry and energy sector of the banking industry. The Executive Vice President of Development reports directly to the Company's Chief Executive Officer.

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 2023, the properties selected for all countries represented 88 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for 91 percent of the value of the Company's international proved reserves and 95 percent of the value of the Company's new wells drilled worldwide. 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 83 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 2023, 2022, and 2021 were:

	2023	**2022**	**2021**
Estimated proved reserves values	88 %	83 %	83 %
Estimated proved reserves volumes:			
United States	83 %	80 %	80 %
Egypt	80 %	80 %	80 %
North Sea	90 %	81 %	81 %
APA Worldwide	83 %	80 %	80 %

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.

ALTUS MIDSTREAM

In November 2018, Apache Midstream LLC, one of the Company's wholly owned subsidiaries completed a transaction with ALTM and its then wholly owned subsidiary Altus Midstream LP to create a pure-play, Permian Basin midstream C-corporation anchored by gathering, processing, and transmission assets at Alpine High. Pursuant to the agreement, the Company's subsidiary contributed certain Alpine High midstream assets and options to acquire equity interests in five separate third-party pipeline projects to Altus Midstream LP and/or its subsidiaries. In exchange for the assets, the Company's subsidiary received economic voting and non-economic voting shares in ALTM and limited partner interests in Altus Midstream LP, representing an approximate 79 percent ownership interest in the combined entities. As a result, APA fully consolidated the assets and liabilities of ALTM in its consolidated financial statements, with a corresponding noncontrolling interest reflected separately.

Business Combination with BCP

On February 22, 2022, ALTM closed a previously announced transaction to combine with privately owned BCP Raptor Holdco LP (BCP and, together with BCP Raptor Holdco GP, LLC, the Contributed Entities) in an all-stock transaction, pursuant to the Contribution Agreement entered into by and among ALTM, Altus Midstream LP, New BCP Raptor Holdco, LLC (the Contributor), and BCP (the BCP Contribution Agreement). The combination created an integrated midstream company in the Texas Delaware Basin offering services for residue gas, NGLs, crude oil and water. Pursuant to the BCP Contribution Agreement, Contributor contributed all of the equity interests of the Contributed Entities (the Contributed Interests) to Altus Midstream LP, with each Contributed Entity becoming a wholly owned subsidiary of Altus Midstream LP (the BCP Business Combination).

As consideration for the contribution of the Contributed Interests, ALTM issued 50 million shares of Class C Common Stock (and Altus Midstream LP issued a corresponding number of common units) to BCP's unitholders, which are principally funds affiliated with Blackstone and I Squared Capital. The transaction closed during the first quarter of 2022. Upon closing the transaction, the combined entity was renamed Kinetik Holdings Inc.

After the transaction closed, Apache Midstream LLC, a wholly owned subsidiary of APA, which owned approximately 79 percent of the issued and outstanding shares of ALTM common stock prior to the BCP Business Combination, owned approximately 20 percent of the issued and outstanding shares of Kinetik common stock. Upon closing the transaction, the Company no longer consolidated the assets and liabilities of ALTM in its consolidated financial statements. Subsequent to the close of the transaction, in March 2022, the Company sold four million of its Kinetik Shares for $224 million, reducing the Company's ownership in Kinetik to approximately 13 percent.

In December 2023, the Company sold an additional 7.5 million of its Kinetik Shares for cash proceeds of $228 million. As of December 31, 2023, the Company owned 13.1 million Kinetik Shares, representing approximately 9 percent of Kinetik's outstanding common stock.

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 each of 2023 and 2022, sales to EGPC accounted for approximately 15 percent of the Company's worldwide crude oil, natural gas, and NGLs revenues. During 2021, sales to EGPC and CFE International accounted for approximately 14 percent and 10 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs revenues.

Management does not believe that the loss of any one of these customers would have a material adverse effect on the results of operations.

HUMAN CAPITAL MANAGEMENT

Human Capital and Employees

APA believes that its people are one of the Company's most important investments and its greatest asset. Successful execution of the Company's business strategies depends on its ability to attract, develop, incentivize, and retain diverse, talented, qualified, and highly skilled employees at all levels of the organization. As such, the Company continues to focus on health and safety, diversity and inclusion, total rewards, and community partnerships to ensure that being a part of the APA family is a positive experience for all.

As of December 31, 2023, the Company globally employed approximately 2,271 full-time equivalent employees in locations across the organization.

	Employees
North America	1,403
United Kingdom	607
Egypt	259
Suriname	—
France	2
Total employees	2,271

Global Workforce		**Global Leadership Roles**		**Board of Directors**	
Gender	**% of Employees**	**Gender**	**% of Employees**	**Gender**	**% of Directors**
F	23%	F	20%	F	30%
M	77%	M	80%	M	70%

Amongst the Company's U.S. workforce, 37 percent self-report as non-white.

U.S. Employees	
Race	**% of Employees**
American Indian or Alaskan Native	— %
Asian	8 %
Black or African American	6 %
Hispanic/Latino	22 %
Native Hawaiian or Other Pacific Islander	— %
Two or More Races	1 %
White	63 %

The Company does not request racial diversity data from its workforce in countries outside of the U.S. where tracking these metrics is largely prohibited by law.

Oversight and Management

The Management Development and Compensation (MD&C) Committee and/or the full Board of Directors receive regular reports on certain human capital matters, including the Company's diversity and inclusion programs and initiatives. The MD&C Committee also oversees the Company's compensation programs, leadership development and succession planning strategies, and seeks continuous improvement in the diversity and inclusion practices used in developing and deploying these processes. Reports and recommendations made to the Board of Directors and its committees are part of the framework that ensures APA's daily actions and decisions are guided by its core values, including upholding the health and safety of the Company's team, stakeholders, and communities; investing in its workforce; ensuring environmental responsibility; seeking continuous improvement; and acting ethically and with integrity.

Diversity and Inclusion

APA recognizes diversity and inclusion (D&I) as vital to its long-term success. The Company has dedicated resources to developing D&I programs and initiatives that foster an inclusive work environment where all employees are valued. The goal is to create a culture where all employees can feel a sense of belonging and can thrive.

In 2023, APA strengthened its commitment by supporting its established programs and expanding employee engagement through the following key accomplishments:

- Increased the number of employee resource groups (ERGs) with the establishment of the Apache Pan Asian Network (APAN), an ERG focused on Asian culture;
- Participated in D&I surveys, networks, and conferences to benchmark against the industry and increase knowledge on D&I best practices;
- Recruited at Historically Black Colleges & Universities (HBCU);
- Developed D&I trainings on mitigating bias in hiring and performance assessment processes;
- Maintained global mentorship program to provide career development through networking with leaders;
- Completed internal annual pay equity analysis;
- Expanded employee benefits to support back-up childcare, mental health services, and family planning;
- Launched a global employee recognition program to increase engagement, inclusion, and employee well-being;
- Increased focus on utilization of supplier diversity program; and
- Continued to support community outreach to underserved populations in the communities in which APA operates.

Talent

APA's comprehensive talent strategy integrates recruitment and development initiatives, forming a foundation for continued organizational success. The Company is dedicated to attracting, cultivating, and retaining top-tier professionals while fostering an environment that encourages growth and innovation.

The Company's recruitment framework harnesses technology and data-driven insights to identify talent pools on a global scale, while at the local level, the Company leverages the power of its people, including, looking to the Company's ERG members for recommendations and feedback during the candidate sourcing and interviewing processes.

Collaborations with educational institutions, including HBCUs, industry networks and professional organizations, such as the Posse Foundation, enable the Company to engage with emerging talent and build relationships with seasoned industry professionals. APA has an intern recruitment program that provides invaluable learning experiences and helps cultivate a pipeline of future industry leaders. Additionally, the Company's recent engagement of the largest black women-owned, diversity-certified recruiting firm specializing in STEM has the goal of amplifying the value and impact of the Company's recruitment program. The firm's expertise, dedicated focus on diversity, and vast network in the STEM fields will help expand the Company's talent pool and reinforce the Company's commitment to fostering a diverse and inclusive working environment. This collaboration not only aligns with the Company's corporate goals but also strengthens the Company's reputation as an organization dedicated to empowering underrepresented groups in STEM. The engagement is a significant stride forward that will enrich the Company's recruitment initiatives and further its commitment to diversity and excellence in the STEM disciplines.

Beyond recruitment, the Company invests in a broad range of talent development programs for its employees. These initiatives encompass continuous learning opportunities, skill enhancement programs, mentorship frameworks, and leadership development pathways. Tailored career progression opportunities empower the Company's employees to excel and innovate, preparing them for evolving challenges.

The synergy between recruitment efforts and talent development initiatives helps the Company to not only attract top talent but to also nurture their potential, enabling them to excel within a dynamic environment. This cohesive approach is designed to provide a continuous influx of skilled individuals who contribute significantly to the Company's growth and maintain a competitive edge, positioning the Company for sustained success in an ever-evolving market landscape.

Training and Development

At APA, effective employee development integrates both training and performance management programs. In 2023, the Company continued to partner with local universities to provide business acumen courses for all employees. Classes were taught in-person as well as offered virtually for the Company's global and remote workforce. Additionally, several in-person and virtual classes on Oil & Gas 101 were rolled out to employees interested in understanding the basics of the industry. APA's Performance Management program moved into a more sustainable phase with a reinforcement on promoting an ongoing feedback culture between managers and employees.

Supplemental development and training opportunities were offered during the year to support employees in their personal and professional development, including:

- Access to multiple, third-party online and in-person trainings;
- Annual cybersecurity training focusing on keeping the Company and employees' personal information secure;
- Required health, safety and environmental trainings offered to field and offshore employees on safe practices;
- Leadership and personal development coaching opportunities through a collaboration with leading human resources consulting companies;
- Ongoing education for people leaders around the Company's leadership competencies and behaviors; and
- Annual compliance, antitrust, bribery, corruption, and code of business conduct and ethics training required for all employees and leaders.

Additionally, the Company launched a company-wide initiative in 2023 focused on enhancing talent strategies and investing in employee development programs that enrich the overall employee experience while reinforcing the Company's organizational objectives.

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, restricted stock units are provided to eligible employees under APA's broad-based 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.

Health and Safety

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 strives to be incident-free 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)	0.22	27% below target of 0.30
Days Away, Restricted and Transferred Rate (DART)(2)	0.14	7% below target of 0.15
Severe Incident Rate (SIR)(3)	0.005	82% below target of 0.028
Vehicle Incident Rate (VIR)(4)	0.65	16% above target of 0.56

(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) Days Away, Restricted and Transferred Rate (DART): The rate of injuries sustained by employees, contractors, or both leading to missed workdays, restricted work activities, or transfers to another job, per 200,000 hours worked.

(3) 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.

(4) Vehicle Incident Rate (VIR): The rate of vehicle-related incidents per 1 million miles driven.

Community Partnerships

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

APA's global giving strategy and philosophy is focused into 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 social 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 underserved 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, including women and children in need; response to natural disasters; and support for first responders.
- Environmental Stewardship: In 2023, the Company's environmental stewardship initiatives included grants of 206,000 trees to 61 community partners through the Apache Corporation Tree Grant Program; continued partnership with the Texas Parks and Wildlife Foundation to provide sustainable funding for the restoration of Balmorhea State Park; and multi-year support of the Pecos Watershed Conservation Initiative, an alliance of seven energy companies, in partnership with the National Fish and Wildlife Foundation, to restore and protect natural grasslands and habitats within the greater Trans-Pecos Region.
- Access to Energy: In 2023, the Company installed generators in the villages of Drietabbetje and Asidonhopo in the Surinamese Amazon, in partnership with the Surinamese Ministry of Natural Resources. The generators not only provide more reliable electricity for the two communities, but they will also help provide better quality health care, increased local trade, more educational opportunities and preserved Indigenous traditions.

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 One Post Oak Central, 2000 Post Oak Boulevard, Suite 100, Houston, Texas 77056-4400. As of year-end 2023, 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, 2024. The Company plans to move its principal executive offices in 2024 to One Briarlake Plaza in Houston, Texas, under an existing lease that expires on 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 11—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 Mexico, the North Sea, and Suriname, which ensure rapid and effective responses to spill events that may occur on such entities' operated properties. Emergency preparedness drills 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 a number of 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 Mexico, Clean Gulf Associates (CGA) is the primary oil spill response association available to Apache. Apache is a member of CGA, a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico. 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 Mexico. 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. The Company utilizes a detailed Source Control Emergency Response Plan (SCERP) for offshore response preparedness. The SCERP has been designed to ensure that the goals of the Company's source control emergency preparedness efforts will be met in the unlikely event of an actual response to an uncontrolled well event. 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 three 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.

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 believe that these requirements affect it differently, to any material degree, than other companies in the oil and gas industry.

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 believe expenses related to training and compliance with regulations and laws that have been adopted or enacted to regulate the discharge of materials into the environment will have a material impact on its capital expenditures, earnings, or competitive position.

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 PRICING, DEMAND, AND PRODUCTION FOR CRUDE OIL, NATURAL GAS, AND NGLs

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 2023 ranged from a high of $93.67 per barrel to a low of $66.61 per barrel, and the NYMEX daily settlement price for the prompt month natural gas contract in 2023 ranged from a high of $3.78 per MMBtu to a low of $1.74 per MMBtu. The market prices for crude oil, natural gas, and NGLs depend on factors beyond the Company's control. These factors include demand, which fluctuates with changes in market and economic conditions, and other factors, including:

- 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, such as the Russian war in Ukraine and the armed conflict in Israel and Gaza;
- 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;
- 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 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. 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, and/or meet volume commitments under transportation services agreements may be adversely affected by pipeline and gathering system capacity constraints, the inability to procure and resell volumes economically, and various transportation interruptions.

A portion of the Company's crude oil, natural gas, and NGL production in any region may be 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 that limit the ability of third parties to construct gathering systems, processing facilities, or interstate pipelines to transport the Company's production. Additionally, the Company may voluntarily curtail production in response to market conditions. 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.

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 future drilling or development activities will not, or are unlikely to, occur for a well or reservoir, based on drilling results, current or future estimated commodity prices or demand for oil, natural gas, and NGLs, or other information. 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.

The Company's commodity price risk management and trading activities may prevent it from benefiting fully from price increases 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. 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.

Global pandemics have previously, may continue to, and may in the future adversely impact the Company's business, financial condition, and results of operations; the global economy; the demand for and prices of oil, natural gas, and NGLs; and the performance of the Company's workforce.

Global pandemics and the actions taken by third parties, including, but not limited to, governmental authorities, businesses, and consumers, in response to such pandemics, including the COVID-19 pandemic, have previously adversely impacted and may from time to time in the future adversely impact the global economy, resulting in significant volatility in the global financial markets, and 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. Additionally, the Company's operations rely on its workforce having access to its wells, platforms, structures, offices, and facilities. If a significant portion of the Company's workforce cannot effectively perform their responsibilities, whether resulting from a lack of physical or virtual access, quarantines, illnesses, governmental actions or restrictions (including vaccine mandates and the reactions thereto), or other restrictions or adverse impacts resulting from a pandemic, the Company's business, financial condition, cash flows, and results of operations may be materially adversely affected.

RISKS RELATED TO OPERATIONS 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, could 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.

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

Demand for oil and natural gas are, 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 Mexico, 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.

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 of the Company’s insurance policies 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, 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 expends significant resources to protect its digital systems and data, whether such data is housed internally or externally by third parties, against cyberattacks and may be required to expend further resources 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.

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 project approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, manufacturing and delivery schedules of critical equipment, 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 AND LEASEHOLD ACREAGE

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, causing reserves quantities to change when actual prices increase or decrease. 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 taxes), future operating, workover, and remediation costs, and capital expenditures. 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 sizeable 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

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, 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 Mexico properties and the bankruptcy of the purchaser of those properties, see the information set forth under "Potential Decommissioning Obligations on Sold Properties" in Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in 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. 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, and, 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

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. During 2023, Moody's upgraded the Company's rating to Baa3/Stable, and Standard and Poor's affirmed the Company's rating as BB+/Positive. 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. This could significantly delay development of the Company's property interests.

The Company's syndicated revolving credit facilities currently mature in April 2027. 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 is subject to limitations.

The payment of future dividends on the Company's capital stock is 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, and restrictions under Delaware law, as well as general business and market conditions. The Board of Directors is not required to declare dividends on APA's common stock and may decide not to declare dividends.

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.

RISKS RELATED TO FINANCIAL RESULTS

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 10—Income Taxes of the Notes to Consolidated Financial Statements included in Item 8 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.

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 only significant assets are the outstanding equity interests of its subsidiaries, including Apache. As a result, APA relies on cash flows from its subsidiaries to pay dividends on its common stock and to meet its financial obligations, including to service any amounts outstanding under its credit agreement 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 RISKS

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 Mexico.

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, and several proposals are before the U.S. Congress that, if implemented, would further regulate, hydraulic fracturing. If adopted, such regulations could 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, which assesses 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. 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.

RISKS RELATED TO CLIMATE CHANGE

The impacts of energy transition could adversely affect the Company's business, operating results, and financial condition.

In recent years, increasing attention has been 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, may result 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.

These 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.

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 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. Moreover, in January 2024, the EPA announced a proposed rule to assess a charge on certain methane emissions in the oil and gas industry. The Company is currently evaluating the proposed rule and its applicability to the Company.

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 annual 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 annual sustainability report. 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 these 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 guidance upon which the Company's consumptive water use reporting was modified and could be revised in the future, resulting in the over or underreporting of the Company's consumptive water use.

In 2022, the Company modified the way it reports its water data compared to previous years and restated its data from prior years. Previously, the Company included produced water usage in its consumptive use calculations, which led to an over-reporting of consumptive water use. Based on re-evaluation of water reporting definitions and guidance, the Company determined that produced water (non-potable water released from deep underground formations and brought to the surface during oil and gas exploration and production) should not be classified as consumed in the same sense as fresh water. The Company's revised reporting now reflects only fresh water and non-potable water from surface water or shallow groundwater that are consumed in oil and gas operations.

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 and appraisal activities offshore Suriname. On a barrel equivalent basis, approximately 46 percent of the Company's 2023 production was outside the U.S., and approximately 30 percent of the Company's estimated proved oil and gas reserves as of December 31, 2023, 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 the laws and regulations applicable to such contracts; import and export regulations; 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; the possibility of being subject to exclusive jurisdiction of foreign courts 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 because of the doctrine of sovereign immunity and foreign sovereignty over international operations.

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 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. 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 further 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.

Further 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, 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, deteriorating 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. A continuation or worsening of the currency shortage in Egypt or further deterioration of economic conditions there could lead to additional payment delays, deferrals of payment, or non-payment in the future. The Company's operations in Egypt, excluding the impacts of a one-third noncontrolling interest, contributed 27 percent of the Company's 2023 production and accounted for 15 percent of the Company's year-end estimated proved reserves and 29 percent of the Company's estimated discounted future net cash flows. If conditions continue to deteriorate 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 between the U.S. dollar and the British 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.

RISKS RELATED TO THE PROPOSED ACQUISITION OF CALLON PETROLEUM COMPANY (CALLON)

The merger is subject to a number of conditions to the obligations of both the Company and Callon to complete the merger, including approval of the Company and Callon stockholders and regulatory clearance, which may impose unacceptable conditions or could delay completion of the merger or result in termination of the Merger Agreement.

On January 3, 2024, the Company entered into a definitive agreement (the Merger Agreement) to acquire Callon. The respective obligations of each of the Company and Callon to consummate the merger are subject to the satisfaction at or prior to the closing of numerous conditions, including the approval of both the Company's and Callon's stockholders, the absence of any law or order prohibiting the consummation of the merger, and the expiration or termination of the waiting period (and any extension of such period) under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. Many of the conditions to completion of the merger are not within either the Company's or Callon's control, and the Company cannot predict when, or if, these conditions will be satisfied. Furthermore, the requirement for obtaining the required regulatory clearances could delay the completion of the merger for a significant period of time or prevent it from occurring. Regulators may seek to enjoin the completion of the merger, seek divestiture of substantial assets of the parties, or require the parties to license, or hold separate, assets or terminate existing relationships and contractual rights.

Failure to complete the merger could negatively impact the Company's stock price and have a material adverse effect on the Company's results of operations, cash flows, and financial position.

If the merger is not completed for any reason, including as a result of failure to obtain all requisite regulatory and stockholder approvals, the ongoing business of the Company may be materially adversely affected and, without realizing any of the benefits of having completed the merger, the Company would be subject to a number of risks, including the following:

- the Company may experience negative reactions from the financial markets, including negative stock price impacts;
- the Company may experience negative reactions from commercial and business partners;
- the Company will still be required to pay significant costs relating to the merger, such as legal, accounting, financial advisor, and printing fees; and
- the Company may be required to pay up to a $170 million termination fee to Callon or reimburse up to $48 million of Callon's expenses, as required by the Merger Agreement.

The pending merger may cause a loss of key employees, disruptions in business relationships, distraction of management, and limitations on the Company's business activities.

Whether or not the merger is completed, the announcement and pendency of the merger could cause disruptions to the Company's business, including:

- uncertainties associated with the merger may cause a loss of management personnel and other key employees of the Company, which could adversely affect the future business and operations of the Company following the merger;
- the business relationships of the Company may be subject to disruption due to uncertainty associated with the merger, which could have a material adverse effect on the Company's results of operations, cash flows, and financial position;
- matters relating to the merger (including integration planning) require substantial commitments of time and resources by the Company's management, which may result in the distraction of the Company's management from ongoing business operations and pursuing other opportunities that could be beneficial to the Company; and
- the Merger Agreement places certain restrictions on the conduct of the Company, which may delay or prevent the Company from undertaking business opportunities that, absent the Merger Agreement, may have been pursued.

The Company may fail to realize the anticipated benefits of the merger and fail to successfully integrate the businesses and operations of the companies in the expected time frame.

The success of the merger will depend on, among other things, the combined company's ability to integrate the Company's and Callon's businesses in a manner that realizes anticipated synergies and benefits and meets or exceeds the forecasted stand-alone cost savings anticipated by the combined company. If the combined company is not able to successfully achieve these synergies, or the cost to achieve these synergies is greater than expected, then the anticipated benefits of the merger may not be realized fully or at all or may take longer to realize than expected. If the transaction closes, it is possible that the integration process could result in the loss of key Company employees or key Callon employees, the loss of customers, providers, vendors, or business partners, the disruption of either company's or both companies' ongoing businesses, inconsistencies in standards, controls, procedures, and policies, potential unknown liabilities and unforeseen expenses, delays, or regulatory conditions associated with and following completion of the merger, or higher than expected integration costs and an overall post-completion integration process that takes longer than originally anticipated.

In addition, at times the attention of certain members of the Company's management and resources may be focused on completion of the merger and planning the integration of the businesses of the two companies and diverted from day-to-day business operations or other opportunities that may have been beneficial to the Company, which may disrupt the Company's ongoing business and the business of the combined company.

Litigation relating to the merger could result in substantial costs to the Company.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger, or other business combination agreements. Even if such a lawsuit is without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on the Company’s liquidity and financial condition.

There can be no assurance that any of the defendants will be successful in the outcome of any pending or any potential future lawsuits. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the Company’s business, financial condition, results of operations, and cash flows.

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, 2023, 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

In 2023, the Company’s Board of Directors established a standing Cybersecurity Committee to assist 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 Chief Information Officer (the CIO) is primarily responsible for the day-to-day operation of the Company's cybersecurity program and for identifying, assessing, and managing the material risks associated with the cybersecurity threats and incidents identified from time to time thereunder. The CIO manages the Company's Information Security Team, which is comprised of cybersecurity professionals responsible for managing the Company's threat intelligence, vulnerability management, forensics, and security architecture systems and processes. The CIO has a Bachelor of Science in Computer Science and over 25 years of experience managing data and technology in the energy industry. He also receives regular updates from external cybersecurity specialists on emerging trends, threats, and technologies in the cybersecurity industry. The CIO reports directly to APA's Executive Vice President, Administration, who, along with the CIO, presents all relevant information to the Cybersecurity Committee.

Additionally, in 2023, the Company established its CyberSmart Defender Network, which is a multi-disciplinary team that includes representatives from across the Company's various departments, responsible for raising awareness of cybersecurity issues, sharing learnings, and gaining access to advanced cybersecurity information and training.

Under the direction of the CIO, 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 11—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, 2024, was $31.33 per share. As of January 31, 2024, there were 301,818,820 shares of APA’s common stock outstanding held by approximately 3,000 stockholders of record and 257,000 beneficial owners.

The Company has paid cash dividends on its common stock for 59 consecutive years through December 31, 2023. During the third quarter of 2022, the Company’s Board of Directors increased the Company’s quarterly dividend from $0.125 per share to $0.25 per share, representing a return to pre-Covid-19 dividend levels. 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 2024 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 2023.

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, 2023	1,115,162	$ 45.96	1,115,162	51,515,635
February 1 to February 28, 2023	—	—	—	51,515,635
March 1 to March 31, 2023	2,547,546	35.85	2,547,546	48,968,089
April 1 to April 30, 2023	—	—	—	48,968,089
May 1 to May 31, 2023	1,348,347	33.72	1,348,347	47,619,742
June 1 to June 30, 2023	—	—	—	47,619,742
July 1 to July 31, 2023	—	—	—	47,619,742
August 1 to August 31, 2023	—	—	—	47,619,742
September 1 to September 30, 2023	477,465	41.90	477,465	47,142,277
October 1 to October 31, 2023	447,228	40.26	447,228	46,695,049
November 1 to November 30, 2023	1,495,986	37.44	1,495,986	45,199,063
December 1 to December 31, 2023	1,279,444	36.95	1,279,444	43,919,619
Total	8,711,178	$ 37.81		

(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, 2018, through December 31, 2023. 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

3109

* $100 invested on 12/31/18 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	2018	2019	2020	2021	2022	2023
APA Corporation	$ 100.00	$ 101.06	$ 56.89	$ 108.53	$ 191.58	$ 150.92
S&P 500 Index	100.00	131.49	155.68	200.37	164.08	207.21
Dow Jones U.S. Exploration & Production Index	100.00	111.39	73.91	126.33	201.59	210.70

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 2023 and 2022 items and year-to-year comparisons between 2023 and 2022. Discussions of 2021 items and year-to-year comparisons between 2022 and 2021 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 Apache Corporation's Annual Report on Form 10-K for the fiscal year ended December 31, 2022 (filed with the SEC on February 23, 2023).

On March 1, 2021, Apache Corporation consummated a holding company reorganization (the Holding Company Reorganization), pursuant to which Apache Corporation became a direct, wholly owned subsidiary of APA Corporation, and all of Apache Corporation's outstanding shares automatically converted into equivalent corresponding shares of APA Corporation. Pursuant to the Holding Company Reorganization, APA Corporation became the successor issuer to Apache Corporation pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache Corporation as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized the Company's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have subsidiaries operating around the globe. As a holding company, APA Corporation's primary assets are its ownership interests in its subsidiaries.

Overview

APA is an independent energy company that owns consolidated subsidiaries that explore for, develop, and produce natural gas, crude oil, and natural gas liquids (NGLs). The Company's upstream 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 exploration and appraisal operations ongoing in Suriname, as well as interests in Uruguay and other international locations that may, over time, result in reportable discoveries and development opportunities. Prior to the BCP Business Combination (as defined in the Notes to the Company's Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K), the Company's midstream business was operated by Altus Midstream Company (ALTM) through its subsidiary Altus Midstream LP (collectively, Altus).

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, including the impact of inflation and rising interest rates, and actions taken by foreign oil and gas producing nations, including OPEC+, continue to impact oil supply and demand and contribute to commodity price volatility. Despite these uncertainties, the Company remains committed to its longer-term objectives: (1) to invest for long-term returns in pursuit of moderate, sustainable production growth; (2) to strengthen 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 (3) to responsibly manage its cost structure regardless of the oil price environment.

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 it the ability to timely respond to near-term price volatility and effectively manage its investment programs accordingly. For example, the Company deferred drilling and completion activity at Alpine High in the second quarter of 2023 in response to weakness in Waha natural gas and NGL prices but accelerated the completion of eight Permian Basin oil producing wells. The Company also suspended drilling activity in the North Sea during the second quarter of 2023, as increasing cost and tax burdens have impacted the competitiveness of these assets within the Company's portfolio. Capital investment plans were then aligned across other areas of the portfolio while maintaining a focus on the Company's capital returns framework established in 2021.

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 cash flow over capital investment 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's quarterly dividend was increased in the third quarter of 2022 from $0.125 per share to $0.25 per share, representing a return to pre-COVID-19 dividend levels.

- Beginning in the fourth quarter of 2021 and through the end of 2023, the Company has repurchased 76.1 million shares of the Company's common stock. Subsequent to year-end 2023 and through the date of this filing on February 22, 2024, the Company repurchased 3.0 million shares, and as of February 22, 2024, the Company had remaining authorization to repurchase up to 40.9 million shares under the Company's share repurchase programs.

Financial and Operational Highlights

During 2023, the Company reported net income attributable to common stock of $2.9 billion, or $9.25 per diluted share, compared to net income of $3.7 billion, or $11.02 per diluted share, in 2022. Net income in 2023 was primarily impacted by lower revenues attributable to significantly lower realized commodity prices compared to 2022. The lower revenues were partially offset by a release of a majority of the Company's U.S. tax valuation allowance, resulting in a non-cash deferred income tax benefit of approximately $1.7 billion during the fourth quarter of 2023. Net income in 2022 also benefited from approximately $1.2 billion of gains from the divestiture of certain non-core mineral rights in the Delaware Basin and completion of the BCP Business Combination.

The Company generated $3.1 billion of cash from operating activities in 2023, which was $1.8 billion or 37 percent lower than 2022. APA's lower operating cash flows for 2023 were driven by lower commodity prices and associated revenues and the timing of working capital items. The Company repurchased 8.7 million shares of its common stock for $329 million and paid $308 million in dividends to APA common stockholders during 2023.

Key operational highlights for the year include:

United States

- Daily boe production from the Company's U.S. assets, which increased 2 percent from 2022, accounted for 54 percent of the Company's worldwide production during 2023. The Company averaged five drilling rigs in the U.S. during the year, including three rigs in the Southern Midland Basin and two rigs in the Delaware Basin, and drilled and brought online 82 operated wells in 2023. The Company's drilling was primarily focused on oil prospects, increasing oil production by approximately 12 percent in the U.S. compared to the prior year. The Company's core Permian Basin development program continues to represent key growth areas for the U.S. assets.
- During the fourth quarter of 2023, the Company commenced an exploration program in Alaska, where it anticipates drilling three exploration wells in the first half of 2024.

International

- In Egypt, the Company continued its drilling and workover activity with a focus on oil prospects. The Company averaged 17 drilling rigs and drilled 91 new productive wells during 2023. During 2023, gross and net production from the Company's Egypt assets decreased 2 percent and 1 percent, respectively, from 2022. The Company continues to build and enhance its drilling inventory in Egypt, supplemented with recent seismic acquisitions and new play concept evaluations on both new and existing acreage opportunities provided by the 2021 merged concession agreement.
- The Company suspended all new drilling activity in the North Sea during the second quarter of 2023. The Company's investment program in the North Sea is now directed toward safety, base production management, and asset maintenance and integrity.

- During 2023, the Company and TotalEnergies announced the launch of development studies for a large oil project in Block 58, offshore Suriname. Successful appraisal of two key oil discoveries, with the drilling and testing of two wells at Sapakara South and three wells at Krabdagu, confirmed combined recoverable resources of an estimated 700 million barrels of oil for the two fields. These fields, located in water depths between 100 and 1,000 meters, are expected to be produced through a system of subsea wells connected to a floating production, storage and offloading unit located 150 kilometers off the Suriname coast, with an oil production capacity of 200,000 b/d. Detailed engineering studies are underway, and a final investment decision is expected by year-end 2024, with a first production target in 2028. No additional drilling is anticipated on Block 58 through the end of 2024.
- During 2023, the Company signed a production sharing contract for Block 6 offshore Uruguay covering approximately four million net undeveloped acres and expects to commence exploration activities in 2024. In February 2024, the Company also signed a production sharing contract for Block 4 offshore Uruguay.

For a more detailed discussion related to the Company's various geographic segments, refer to "Upstream Exploration and Production Properties—Operating Areas" set forth in Part I, Item 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:

- *Callon Petroleum Company Pending Acquisition* On January 3, 2024, APA and Callon Petroleum Company (Callon) entered into a definitive agreement (Merger Agreement), pursuant to which APA will acquire Callon in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's net debt.

  In this all-stock transaction, each eligible outstanding share of Callon common stock will be exchanged for 1.0425 shares of APA common stock, representing an implied value to each Callon share of $38.31 per share based on the closing price of APA common stock on January 3, 2024. After closing, existing APA shareholders are expected to own approximately 81 percent of the combined company, and existing Callon shareholders are expected to own approximately 19 percent of the combined company. APA expects to retire the existing debt at Callon and replace it with APA term loan facilities totaling $2.0 billion.

  The transaction has been unanimously approved by the boards of directors of both APA and Callon and is expected to close during the second quarter of 2024, subject to customary closing conditions, termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and approval of the transaction by shareholders of both APA and Callon. This transaction complements and enhances APA's asset base in the Permian Basin and adds to APA's inventory of high quality, short-cycle opportunities. In addition, Callon's assets provide additional scale to APA's operations across the Permian Basin.

- *BCP Business Combination* On February 22, 2022, ALTM closed a transaction to combine with privately owned BCP Raptor Holdco LP (BCP) in an all-stock transaction. Upon closing the transaction, the combined entity was renamed Kinetik Holdings Inc. (Kinetik). The Company deconsolidated ALTM upon closing the transaction. The deconsolidation provides a number of benefits to APA shareholders, including simplification of the Company's financial reporting and enhanced comparability with its upstream-only peers, while maintaining a noncontrolling interest in future growth opportunities of Kinetik.
- *Delaware Basin Acquisition* In the third quarter of 2022, the Company closed on the acquisition of oil and gas assets surrounding core acreage in the Delaware Basin for approximately $615 million after post-closing adjustments. Final cash settlements of $24 million were completed during 2023.
- *Sales of Kinetik Shares* Subsequent sales of Kinetik Shares have reduced APA's ownership in Kinetik to approximately 9 percent as of December 31, 2023. During 2023, the Company sold a portion of its Kinetik Shares for cash proceeds of $228 million. During 2022, the Company sold a portion of its Kinetik Shares for $224 million.

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,					
	2023		2022		2021	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
	($ in millions)					
Oil Revenues:						
United States	$ 2,241	37 %	$ 2,458	36 %	$ 1,850	40 %
Egypt[(1)]	2,683	45 %	3,145	46 %	1,806	40 %
North Sea	1,073	18 %	1,232	18 %	929	20 %
Total[(1)]	$ 5,997	100 %	$ 6,835	100 %	$ 4,585	100 %
Natural Gas Revenues:						
United States	$ 297	34 %	$ 918	59 %	$ 754	62 %
Egypt[(1)]	346	39 %	370	23 %	270	23 %
North Sea	237	27 %	281	18 %	183	15 %
Total[(1)]	$ 880	100 %	$ 1,569	100 %	$ 1,207	100 %
NGL Revenues:						
United States	$ 480	94 %	$ 765	94 %	$ 673	95 %
Egypt[(1)]	—	— %	6	1 %	9	1 %
North Sea	28	6 %	45	5 %	24	4 %
Total[(1)]	$ 508	100 %	$ 816	100 %	$ 706	100 %
Oil and Gas Revenues:						
United States	$ 3,018	41 %	$ 4,141	45 %	$ 3,277	50 %
Egypt[(1)]	3,029	41 %	3,521	38 %	2,085	32 %
North Sea	1,338	18 %	1,558	17 %	1,136	18 %
Total[(1)]	$ 7,385	100 %	$ 9,220	100 %	$ 6,498	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,				
	2023	Increase (Decrease)	2022	Increase (Decrease)	2021
Oil Volumes – b/d:					
United States[5]	78,889	12%	70,398	(6)%	75,205
Egypt[3][4]	89,129	5%	85,081	21%	70,349
North Sea	34,728	7%	32,578	(10)%	36,265
Total	202,746	8%	188,057	3%	181,819
Natural Gas Volumes – Mcf/d:					
United States[5]	452,281	(4)%	473,292	(10)%	527,461
Egypt[3][4]	325,778	(9)%	356,327	35%	263,653
North Sea	50,284	42%	35,327	(8)%	38,565
Total	828,343	(4)%	864,946	4%	829,679
NGL Volumes – b/d:					
United States[5]	62,997	—%	62,727	(5)%	66,232
Egypt[3][4]	—	NM	196	(63)%	531
North Sea	1,240	12%	1,111	(7)%	1,199
Total	64,237	—%	64,034	(6)%	67,962
BOE per day:[1]					
United States[5]	217,266	2%	212,007	(8)%	229,348
Egypt[3][4]	143,425	(1)%	144,665	26%	114,821
North Sea[2]	44,349	12%	39,577	(10)%	43,892
Total	405,040	2%	396,249	2%	388,061

(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 45,476 boe/d, 40,812 boe/d, and 44,179 boe/d for 2023, 2022, and 2021, 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:

	2023	2022	2021
Oil (b/d)	141,985	137,260	134,711
Natural Gas (Mcf/d)	500,080	555,562	586,663
NGL (b/d)	—	297	854

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

	2023	2022	2021
Oil (b/d)	29,739	28,200	23,504
Natural Gas (Mcf/d)	108,703	118,074	88,409
NGL (b/d)	—	65	177

(5) Production volumes per day in the Company’s Alpine High field were as follows:

	2023	2022	2021
Oil (b/d)	573	777	1,485
Natural Gas (Mcf/d)	174,454	192,253	258,096
NGL (b/d)	16,482	18,362	22,950

NM — Not Meaningful

Pricing

The following table presents pricing information by country:

	For the Year Ended December 31,							
		2023	**Increase (Decrease)**		**2022**	**Increase (Decrease)**		**2021**
Average Oil Price - Per barrel:								
United States	$	77.84	(19)%	$	95.68	42%	$	67.37
Egypt		82.47	(19)%		101.25	44%		70.33
North Sea		82.75	(18)%		100.87	45%		69.67
Total		80.72	(19)%		99.11	44%		68.97
Average Natural Gas Price - Per Mcf:								
United States	$	1.80	(66)%	$	5.31	35%	$	3.92
Egypt		2.91	2%		2.85	1%		2.81
North Sea		13.02	(44)%		23.36	80%		12.96
Total		2.91	(42)%		4.98	25%		3.99
Average NGL Price - Per barrel:								
United States	$	20.85	(38)%	$	33.41	20%	$	27.85
Egypt		—	NM		76.80	57%		48.84
North Sea		47.77	(29)%		67.07	24%		54.30
Total		21.54	(38)%		34.51	21%		28.48

NM — Not Meaningful

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 2023 were down 19 percent compared to 2022, a direct result of decreasing benchmark oil prices over the past year. Crude oil prices realized in 2023 averaged $80.72 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 $1.80 per Mcf in 2023, a 66 percent decrease from an average of $5.31 per Mcf in 2022.
- In Egypt, the Company’s natural gas is sold to EGPC, primarily under an industry-pricing formula, a sliding scale based on Dated Brent crude oil with a minimum of $1.50 per MMBtu and a maximum of $2.65 per MMBtu, plus an upward adjustment for liquids content. Overall, the Company’s Egypt operations averaged $2.91 per Mcf in 2023, a 2 percent increase from an average of $2.85 per Mcf in 2022.
- 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 $13.02 per Mcf in 2023, a 44 percent decrease from an average of $23.36 per Mcf in 2022.

NGL Prices The Company's U.S. NGL production, which accounted for 98 percent of the Company's total 2023 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 2023 totaled $6.0 billion, an $838 million decrease from the 2022 total of $6.8 billion. A 19 percent decrease in average realized prices reduced 2023 revenues by $1.3 billion compared to 2022, while 8 percent higher average daily production increased revenues by $430 million. Average daily production in 2023 was 203 Mb/d, with prices averaging $80.72 per barrel. Crude oil sales accounted for 81 percent of the Company's 2023 oil and gas production revenues and 50 percent of its worldwide production.

The Company's worldwide crude oil production increased 15 Mb/d compared to 2022, primarily a result of increased drilling activity in the U.S. and Egypt, and less maintenance downtime in the North Sea, partially offset by natural production decline across all assets.

Natural Gas Revenues

Natural gas revenues for 2023 totaled $880 million, a $689 million decrease from the 2022 total of $1.6 billion. A 42 percent decrease in average realized prices reduced 2023 revenues by $652 million compared to 2022, while 4 percent lower average daily production decreased revenues by $37 million. Average daily production in 2023 was 828 MMcf/d, with prices averaging $2.91 per Mcf. Natural gas sales accounted for 12 percent of the Company's 2023 oil and gas production revenues and 34 percent of its worldwide production.

The Company's worldwide natural gas production decreased 37 MMcf/d compared to 2022, primarily a result of natural production decline across all assets and the sale of non-core assets in the U.S., partially offset by increased drilling activity and recompletions and less maintenance downtime in the North Sea.

NGL Revenues

NGL revenues for 2023 totaled $508 million, a $308 million decrease from the 2022 total of $816 million. A 38 percent decrease in average realized prices primarily drove the decrease in NGL revenues compared to 2022. Average daily production in 2023 was 64 Mb/d, with prices averaging $21.54 per barrel. NGL sales accounted for 7 percent of the Company's 2023 oil and gas production revenues and 16 percent of its worldwide production.

The Company's worldwide NGL production increased slightly compared to 2022, primarily a result of increased drilling activity and recompletions and less maintenance downtime in the North Sea, offset by natural production decline across all assets.

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. In 2023, in order to diversify the pricing received for the sale of its natural gas, the Company sold a portion of its purchased gas at international gas prices. Sales related to purchased volumes decreased $961 million for the year ended December 31, 2023 to $894 million from $1.9 billion in 2022. Purchased oil and gas sales were partially offset by associated purchase costs of $742 million and $1.8 billion for the years ended December 31, 2023 and 2022, respectively. The decrease in purchased oil and gas sales is primarily a result of lower average domestic natural gas prices during 2023 compared to 2022.

Operating Expenses

The table below presents a comparison of the Company's operating expenses for the years ended December 31, 2023, 2022, and 2021. All operating expenses include costs attributable to a noncontrolling interest in Egypt and Altus.

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Lease operating expenses	$ 1,436	$ 1,444	$ 1,241
Gathering, processing, and transmission	334	367	264
Purchased oil and gas costs	742	1,776	1,580
Taxes other than income	207	268	204
Exploration	195	305	155
General and administrative	351	483	376
Transaction, reorganization, and separation	15	26	22
Depreciation, depletion, and amortization:			
Oil and gas property and equipment	1,500	1,186	1,255
Gathering, processing, and transmission assets	6	15	64
Other assets	34	32	41
Asset retirement obligation accretion	116	117	113
Impairments	61	—	208
Financing costs, net	312	379	514

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 50 percent of the Company's total 2023 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties.

During 2023, LOE decreased $8 million, or 1 percent, compared to 2022. On a per-boe basis, LOE decreased $0.27, or 3 percent, compared to 2022, from $9.95 per boe to $9.68 per boe. The decrease in costs was driven by lower average foreign currency exchange impacts against the U.S. dollar and decreased workover activity primarily in the North Sea. These decreases were mostly offset by higher labor costs and other operating costs trending with general inflation across all regions.

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. Prior to the BCP Business Combination and the Company's deconsolidation of Altus on February 22, 2022, GPT expenses also included gathering and transmission services provided by Altus Midstream and midstream operating costs incurred by Altus. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Third-party processing and transmission costs	$ 225	$ 269	$ 232
Midstream service costs – ALTM	—	18	128
Midstream service costs – Kinetik	109	93	—
Upstream processing and transmission costs	334	380	360
Midstream operating expenses	—	5	32
Intersegment eliminations	—	(18)	(128)
Total Gathering, processing, and transmission	$ 334	$ 367	$ 264

GPT costs decreased $33 million compared to 2022, primarily the result of lower upstream processing and transmission costs, partially offset by impacts of the BCP Business Combination. Upstream processing and transmission costs decreased $46 million from 2022, primarily driven by a decrease in natural gas production volumes when compared to the prior-year period. Costs for services provided by ALTM in 2022 prior to the BCP Business Combination totaling $18 million were eliminated in the Company's consolidated financial statements and reflected as "Intersegment eliminations" in the table above. Subsequent to the Company's deconsolidation of Altus in February 2022, these midstream services continue to be provided by Kinetik but are no longer eliminated.

Purchased Oil and Gas Costs

Purchased oil and gas costs decreased $1.0 billion for the year ended December 31, 2023, to $742 million from $1.8 billion in 2022. The decrease is a result of lower average domestic natural gas prices during 2023 compared to the prior year. Purchased oil and gas costs were more than offset by associated sales to fulfill natural gas takeaway obligations and delivery commitments totaling $894 million for the year ended 2023, as discussed above.

*Taxes Other Than Incom*e

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 $61 million compared to 2022, primarily from lower severance taxes driven by lower commodity prices and lower ad valorem tax rates.

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,		
	2023	**2022**	**2021**
		(In millions)	
Unproved leasehold impairments	$ 22	$ 24	$ 31
Dry hole expenses	92	183	66
Geological and geophysical expenses	19	23	18
Exploration overhead and other	62	75	40
Total Exploration	$ 195	$ 305	$ 155

Exploration expenses decreased $110 million compared to 2022, primarily the result of higher dry hole expense in Suriname during 2022 coupled with lower exploration overhead and other activities in 2023.

General and Administrative (G&A) Expenses

G&A expenses decreased $132 million compared to 2022, primarily driven by lower cash-based stock compensation expense during 2023 resulting from decreases in the Company's stock price and in the achievement of performance and financial objectives as defined in the stock award plans. For additional information refer to Note 14—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 $11 million compared to 2022. Higher TRS costs in 2022 were incurred in connection with the BCP Business Combination in the first quarter of 2022.

Depreciation, Depletion and Amortization (DD&A)

DD&A expenses on the Company's oil and gas property for the year ended December 31, 2023 increased $314 million compared to 2022. The Company's oil and gas property DD&A rate increased $1.94 per boe in 2023 compared to 2022, from $8.18 per boe to $10.12 per boe, driven by general cost inflation and the unit of production impact of lower proved reserves during 2023. The increase on an absolute basis was also impacted by an increase in capital investment activity in Egypt and acquisitions in the U.S.

Impairments

During 2023, the Company recorded $61 million of impairments, primarily in connection with valuations of drilling and operations equipment inventory upon the Company's decision to suspend drilling operations in the North Sea. No asset impairments were recorded in 2022.

Financing Costs, Net

Financing costs incurred during 2023, 2022, and 2021 comprised the following:

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Interest expense	$ 351	$ 332	$ 419
Amortization of debt issuance costs	4	8	8
Capitalized interest	(24)	(18)	(9)
Loss (gain) on extinguishment of debt	(9)	67	104
Interest income	(10)	(10)	(8)
Total Financing costs, net	$ 312	$ 379	$ 514

Net financing costs during 2023 decreased $67 million compared to 2022, primarily driven by losses incurred on the extinguishment of debt during 2022 and gains on extinguishment of debt during 2023, partially offset by an increase in interest expense during 2023 related to higher variable interest rates on credit facility borrowings.

Provision for Income Taxes

Income tax expense decreased $2.0 billion from $1.7 billion during 2022 to an income tax benefit of $324 million during 2023. The Company's 2023 effective income tax rate was primarily impacted by a deferred tax expense related to the release of a portion of its valuation allowance against U.S. deferred tax assets and the remeasurement of taxes in the U.K. as a result of the enactment of Finance Act 2023 on January 10, 2023. During 2022, the Company's effective income tax rate was primarily impacted by a deferred tax expense related to the remeasurement of taxes in the U.K. as a result of the enactment of the Energy (Oil and Gas) Profits Levy Act of 2022 (the Energy Profits Levy) on July 14, 2022, and a decrease in the amount of valuation allowance against its U.S. deferred tax assets.

On July 14, 2022, the Energy Profits Levy was enacted, receiving Royal Assent. Under the law, an additional levy was assessed at a 25 percent rate and is effective for the period of May 26, 2022, through December 31, 2025. The Finance Act 2023 included amendments to the Energy Profits Levy that increased the levy from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023 through March 31, 2028. Under accounting principles generally accepted in the U.S., the financial statement impact of new legislation is recorded in the period of enactment. As a result, the Company recorded a deferred tax expense of $208 million and $174 million related to the remeasurement of the U.K. deferred tax liability in 2022 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 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 is not an applicable corporation in 2023 but will be subject to CAMT beginning on January 1, 2024. The Company is continuing to evaluate the provisions of the IRA and its effects on the Company's consolidated financial statements.

In December 2021, the Organisation for Economic Co-operation and Development (OECD) released Model Rules under the Pillar Two framework, which imposes a 15 percent global minimum tax on large corporations. Such Model Rules have been adopted in certain jurisdictions in which the Company operates, including the United Kingdom, with an effective date of January 1, 2024. While the Company does not anticipate that Pillar Two will have a material impact on its effective tax rate, the Company will continue to evaluate the potential impacts of enacted and pending legislation in the jurisdictions in which it operates.

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. The Company showed positive income over the three-year period ended December 31, 2023. 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. The remaining U.S. valuation allowance relates primarily to foreign tax credit and capital loss carryforwards.

For additional information regarding income taxes, refer to Note 10—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. On September 26, 2022, the Company received a Statutory Notice of Deficiency from the IRS disallowing certain net operating loss carryback and research and development credit refund claims. As a result of the disallowance, on December 14, 2022, the Company filed a petition with the U.S. Tax Court challenging the tax adjustments and requesting a redetermination of the deficiencies stated in the notice. The Company is also under audit in various states 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 remains committed to its longer-term objectives: (1) to invest for long-term returns in pursuit of moderate, sustainable production growth; (2) to strengthen 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 (3) to responsibly manage its cost structure regardless of the oil price environment.

In 2024, the Company plans to invest $1.9 to $2.0 billion in upstream capital investment. This investment level reflects the Company's strategy of moderating activity levels during periods of lower commodity prices. APA will invest for the long term by directing $100 million of the 2024 upstream budget toward exploration activities predominantly in Alaska and $50 million toward progressing a large-scale floating production storage and offloading (FPSO) project in Suriname. The Company's worldwide adjusted oil and natural gas production is expected be relatively flat year over year, while NGL volumes are anticipated to be lower as the current strip prices would lead to ethane rejection in the U.S. for most of the year.

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.

For the year ended December 31, 2023, the Company recognized a slight downward reserve revision related to decreases in commodity prices during the year. The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2023, 2022, and 2021, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 18—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,		
	2023	2022	2021
		(In millions)	
Sources of Cash and Cash Equivalents:			
Net cash provided by operating activities	$ 3,129	$ 4,943	$ 3,496
Proceeds from revolving credit facilities, net	—	24	392
Proceeds from asset divestitures	29	778	256
Proceeds from sale of Kinetik shares	228	224	—
Total Sources of Cash and Cash Equivalents	3,386	5,969	4,144
Uses of Cash and Cash Equivalents:			
Additions to upstream oil and gas property(1)	2,313	1,770	1,101
Acquisition of Delaware Basin properties	24	591	—
Leasehold and property acquisitions	20	37	9
Payments on revolving credit facilities, net	194	—	—
Payments on Apache fixed-rate debt	65	1,493	1,795
Dividends paid to APA common stockholders	308	207	52
Distributions to noncontrolling interest – Egypt	238	362	279
Treasury stock activity, net	329	1,423	847
Deconsolidation of Altus cash and cash equivalents	—	143	—
Other, net	53	—	21
Total Uses of Cash and Cash Equivalents	3,544	6,026	4,104
Increase (decrease) in cash and cash equivalents	$ (158)	$ (57)	$ 40

(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, 2023 totaled $3.1 billion, down $1.8 billion from the year ended December 31, 2022, primarily the result of significantly lower commodity prices and associated revenues and timing of 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.

Proceeds from Asset Divestitures The Company received $29 million and $778 million in proceeds from the divestiture of certain non-core assets during the years ended December 31, 2023 and 2022, respectively. For more information regarding the Company’s acquisitions and divestitures and equity method interests, 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.

Proceeds from Sale of Kinetik Shares The Company received $228 million and $224 million of cash proceeds from the sales of its Kinetik Shares during 2023 and 2022, respectively. For more information regarding the Company’s equity method interests, refer to Note 6—Equity Method Interests 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 Upstream Oil & Gas Property Exploration and development cash expenditures were $2.3 billion and $1.8 billion for the years ended December 31, 2023 and 2022, respectively. The increase is reflective of the Company's capital program in 2023 and its focus to balance capital investments with cash flow from operations, debt repayment, and capital returns to shareholders. The Company operated an average of 24 drilling rigs during 2023, compared to an average of 22 drilling rigs during 2022.

Acquisition of Delaware Basin Properties During 2022, the Company closed on the acquisition of oil and gas assets in the Delaware Basin for a total purchase price of $615 million after post-closing adjustments. Final cash settlements of $24 million were completed during 2023. Cash consideration paid during 2022 totaled $591 million.

Leasehold and Property Acquisitions During 2023 and 2022, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $20 million and $37 million, respectively.

Payments on Revolving Credit Facilities, Net As of December 31, 2023, outstanding borrowings under the Company's U.S. dollar denominated syndicated credit facility were $372 million, a decrease of $194 million from December 31, 2022 as operating cash flows generated in 2023 were used to repay facility borrowings.

Payments on Fixed-Rate Debt 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.

During 2022, Apache closed cash tender offers for certain outstanding notes issued under its indentures, accepting for purchase $1.1 billion aggregate principal amount of notes. Apache paid holders an aggregate $1.2 billion in cash, reflecting principal, premium to par, and accrued and unpaid interest. The Company recognized a $66 million loss on extinguishment of debt, including $11 million of unamortized debt discount and issuance costs in connection with the note purchases. The repurchases were partially financed by borrowing under Apache's former revolving credit facility.

During 2022, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $15 million for an aggregate purchase price of $16 million in cash, including accrued interest and broker fees, reflecting a premium to par of an aggregate $1 million. The Company recognized a $1 million loss on these repurchases. The repurchases were partially financed by borrowing under Apache's former revolving credit facility.

On October 17, 2022, Apache redeemed the outstanding $123 million outstanding principal amount of 2.625% notes due January 15, 2023, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The redemption was financed in part by Apache's borrowing under the Company's U.S. dollar-denominated revolving credit facility.

On January 18, 2022, Apache redeemed the outstanding $213 million principal amount of 3.25% senior notes due April 15, 2022, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The redemption was financed by borrowing under Apache's former revolving credit facility.

The Company expects that Apache will continue to reduce debt outstanding under its indentures from time to time.

Dividends Paid to APA Common Stockholders The Company paid $308 million and $207 million during the years ended December 31, 2023 and 2022, respectively, for dividends on its common stock. During the third quarter of 2022, the Company's Board of Directors approved an increase to its quarterly dividend from $0.125 per share to $0.25 per share.

Distributions to Noncontrolling Interest - Egypt Sinopec holds a one-third minority participation interest in the Company's oil and gas operations in Egypt. The Company paid $238 million and $362 million during the years ended December 31, 2023 and 2022, respectively, in cash distributions to Sinopec.

Treasury Stock Activity, Net During 2023, the Company repurchased 8.7 million shares at an average price of $37.81 per share totaling $329 million, and as of December 31, 2023, the Company had remaining authorization to repurchase 43.9 million shares. During 2022, the Company repurchased 36.2 million shares at an average price of $39.34 per share totaling $1.4 billion.

Liquidity

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

	2023	2022
	(In millions)	
Cash and cash equivalents	$ 87	$ 245
Total debt – APA and Apache	5,188	5,453
Total equity	3,691	1,345
Available committed borrowing capacity under syndicated credit facilities	2,894	2,238

Cash and Cash Equivalents As of December 31, 2023, the Company had $87 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, 2023, the Company had $5.2 billion in total debt outstanding, which consisted of notes and debentures of Apache, credit facility borrowings, and finance lease obligations. As of December 31, 2023, current debt included $2 million of finance lease obligations.

Committed 2022 Credit Facilities On April 29, 2022, the Company entered into two unsecured syndicated credit agreements for general corporate purposes that replaced and refinanced Apache's 2018 unsecured syndicated credit agreement (the Former Facility).

- One agreement is denominated in US dollars (the USD Agreement) and provides for an unsecured five-year revolving credit facility, with aggregate commitments of US$1.8 billion (including a letter of credit subfacility of up to US$750 million, of which US$150 million currently is committed). The Company may increase commitments up to an aggregate US$2.3 billion by adding new lenders or obtaining the consent of any increasing existing lenders. This facility matures in April 2027, subject to the Company's two, one-year extension options.

- The second agreement is denominated in pounds sterling (the 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 April 2027, subject to the Company's two, one-year extension options.

In connection with the Company's entry into the USD Agreement and the GBP Agreement (each, a 2022 Agreement), Apache terminated US$4.0 billion of commitments under the Former Facility, borrowings then outstanding under the Former Facility were deemed outstanding under the USD Agreement, and letters of credit then outstanding under the Former Facility were deemed outstanding under a 2022 Agreement, depending upon whether denominated in US dollars or pounds sterling. Apache may borrow under the USD Agreement up to an aggregate principal amount of US$300 million outstanding at any given time. Apache has guaranteed obligations under each 2022 Agreement effective until the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures is less than US$1.0 billion.

As of December 31, 2023, there were $372 million of borrowings under the USD Agreement and an aggregate £348 million in letters of credit outstanding under the GBP Agreement. As of December 31, 2023, there were no letters of credit outstanding under the USD Agreement. As of December 31, 2022, there were $566 million of borrowings and a $20 million letter of credit outstanding under the USD Agreement, and an aggregate £652 million in letters of credit outstanding under the GBP Agreement. The letters of credit denominated in pounds were issued to support North Sea decommissioning obligations, the terms of which require such support while Apache's credit rating by Standard & Poor's remains below BBB; on March 26, 2020, Standard & Poor's reduced Apache's rating from BBB to BB+, which was affirmed in 2023.

All borrowings under the 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 ranging from 0.10% to 0.675% (Base Rate Margin), or an adjusted term SOFR rate (as defined), plus a margin varying from 1.10% to 1.675% (Applicable Margin). All borrowings under the GBP Agreement bear interest at an adjusted rate per annum determined by reference to the Sterling Overnight Index Average published by the Bank of England, plus the Applicable Margin. Each 2022 Agreement also requires the borrower to pay quarterly a facility fee on total commitments. 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, or if such indebtedness is not rated and the Apache guaranty is in effect, of Apache (Long-Term Debt Rating). As of December 31, 2023, Apache's Long-Term Debt Rating applied, and the Base Rate Margin was 0.40%, the Applicable Margin was 1.40%, and the facility fee was 0.225%.

A commission is payable quarterly to lenders under each 2022 Agreement 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.

Borrowers under each 2022 Agreement, which may 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 substantially similar to those in the Former Facility, such as:

- A financial covenant requires APA to maintain an adjusted debt-to-capital ratio of not greater than 60 percent at the end of any fiscal quarter. For purposes of this calculation, capital continues to exclude the effects of non-cash write-downs, impairments, and related charges occurring after June 30, 2015. At December 31, 2023, APA's debt-to-capital ratio as calculated under each 2022 Agreement was 20 percent.

- A negative covenant restricts the ability of APA and its subsidiaries to create liens securing debt on their hydrocarbon-related assets, with exceptions for liens typically arising in the oil and gas industry; liens securing debt incurred to finance the acquisition, construction, improvement, or capital lease of assets, provided that such debt, when incurred, does not exceed the subject purchase price and costs, as applicable, and related expenses; liens on subsidiary assets located outside of the U. S. and Canada; and liens arising as a matter of law, such as tax and mechanics' liens. Liens on assets also are permitted if debt secured thereby does not exceed 15 percent of APA's consolidated net tangible assets or approximately $1.9 billion as of December 31, 2023.

- 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.

Consistent with the Former Facility, the 2022 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 each 2022 Agreement as of December 31, 2023.

There is no assurance of the terms upon which potential lenders under future credit facilities will make loans or other extensions of credit available to APA or its subsidiaries or the composition of such lenders.

There is no assurance that the financial condition of banks with lending commitments to APA or its subsidiaries will not deteriorate. The Company closely monitors the ratings of the banks in its bank groups. Having large bank groups allows the Company to mitigate the potential impact of any bank's failure to honor its lending commitment.

Uncommitted Credit Facilities 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, 2023 and 2022, there were no outstanding borrowings under these facilities. As of December 31, 2023, there were £416 million and $2 million in letters of credit outstanding under these facilities. As of December 31, 2022, there were £199 million and $17 million in letters of credit outstanding under these facilities.

Commercial Paper Program On December 13, 2023, the Company established 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 (the CP Notes) up to a maximum aggregate face amount of $1.8 billion outstanding at any time. The Company intends to use net proceeds of the CP Notes for general corporate purposes.

Payment of the CP Notes has been 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 is less than US$1.0 billion.

The CP Notes will be 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. The maturities of the CP Notes may vary but may not exceed 397 days from the date of issuance.

As of December 31, 2023, the Company had not issued any CP Notes.

Committed Delayed-Draw Term Loan Facility. On January 30, 2024, APA entered into a syndicated credit agreement under which the lenders have committed an aggregate $2.0 billion for senior unsecured delayed-draw term loans to APA (Credit Agreement). Subject to satisfaction of certain limited conditions, APA may borrow under the Credit Agreement to refinance certain indebtedness of Callon Petroleum Company, a Delaware corporation (Callon), upon or after closing of APA's pending acquisition of Callon pursuant to the previously announced Agreement and Plan of Merger among APA, Astro Comet Merger Sub Corp., a Delaware corporation and wholly owned subsidiary of APA, and Callon, dated January 3, 2024 (Merger Agreement).

Two tranches of term loans would be available to APA for borrowing only on the date of closing of transactions under the Merger Agreement and satisfaction of certain other conditions under the Credit Agreement (Closing Date); of the aggregate $2.0 billion in commitments, $1.5 billion is for term loans that would mature three years after the Closing Date (3-Year Tranche Loans) and $500 million is for term loans that would mature 364 days after the Closing Date (364-Day Tranche Loans).

Indebtedness of Callon that APA could refinance by borrowing under the Credit Agreement on the Closing Date includes indebtedness outstanding under (i) the Amended and Restated Credit Agreement, dated October 19, 2022, among Callon, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (Callon Credit Agreement), (ii) Callon's 6.375% Senior Notes due 2026 (Callon's 2026 Notes), (iii) Callon's 8.00% Senior Notes due 2028 (Callon's 2028 Notes), and (iv) Callon's 7.500% Senior Notes due 2030 (Callon's 2030 Notes, and together with the Callon Credit Agreement, Callon's 2026 Notes, and Callon's 2028 Notes, the Callon Indebtedness).

The Credit Agreement has limited conditions to funding on the Closing Date loans requested by APA in accordance with the Credit Agreement, such as consummation of the transactions under the Merger Agreement, no Company Material Adverse Effect (as defined in the Merger Agreement) has occurred, repayment of all indebtedness outstanding under the Callon Credit Agreement and Callon's 2026 Notes, and Callon having no other material indebtedness for borrowed money except for Callon's 2028 Notes and Callon's 2030 Notes or as permitted under the Credit Agreement or the Merger Agreement.

Proceeds of loans made under the Credit Agreement may only be used to refinance the Callon Indebtedness and repay fees and expenses related to transactions under the Credit Agreement and the Merger Agreement. To the extent that borrowings by APA under the Credit Agreement are not so used on or before the date that is 120 days after the Closing Date, APA then must prepay the amount of such unused borrowings.

Apache has guaranteed obligations under the Credit Agreement effective until the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures first is less than $1.0 billion.

If $400 million or more in aggregate principal amount of Callon's 2028 Notes and Callon's 2030 Notes remains outstanding on the date which is 120 days after the Closing Date, Callon then must guarantee APA's obligations under the Credit Agreement effective until the aggregate outstanding principal amount of Callon's 2028 Notes and Callon's 2030 Notes first is less than $400 million.

APA may at any time prepay loans under the Credit Agreement. APA may at any time terminate, or from time to time reduce, the lenders' commitments under the Credit Agreement. Unless previously terminated, the lenders' commitments automatically terminate on the first to occur of: (i) the Closing Date, after giving effect to funding of each lender's commitments on the Closing Date, (ii) APA's acquisition of Callon pursuant to the Merger Agreement without loans being made under the Credit Agreement, (iii) termination of the Merger Agreement in accordance with its terms, and (iv) the Termination Date (as defined in, and may be extended pursuant to, the Merger Agreement).

All borrowings under the Credit Agreement would be in U.S. Dollars and bear interest at one of the following two rate options, as selected by APA, plus the indicated margin:

- One option is a base rate per annum equal to the greatest of (i) the applicable prime rate, (ii) the greater of the applicable federal funds rate and overnight bank funding rate, plus 0.50%, and (iii) an adjusted secured overnight financing rate published by the Federal Reserve Bank of New York (SOFR) for a one-month interest period plus 1.0%. The margin for this rate option (Term Base Rate Margin) is a rate per annum varying from 0.25% to 1.0% for 364-Day Tranche Loans, 0.375% to 1.125% for 3-Year Tranche Loans until the second anniversary of the Closing Date, and 0.625% to 1.375% for 3-Year Tranche Loans after the second anniversary of the Closing Date, in each case, based on the rating for senior, unsecured, non-credit enhanced, long-term indebtedness for borrowed money of APA, or if such indebtedness is not rated and the Apache guaranty is in effect, of Apache. Apache's Long-Term Debt Rating currently applies.

- The second option is an adjusted SOFR rate, plus a margin at a rate per annum varying from 1.25% to 2.0% for 364-Day Tranche Loans, 1.375% to 2.125% for 3-Year Tranche Loans until the second anniversary of the Closing Date, and 1.625% to 2.375% for 3-Year Tranche Loans after the second anniversary of the Closing Date, in each case, based on the Long-Term Debt Rating (Term Applicable Margin). For SOFR-based interest rates, APA may select an interest period of one, three, or six months.

Currently, the Term Base Rate Margin is 0.625% for 364-Day Tranche Loans and 0.75% for 3-Year Tranche Loans, and the Term Applicable Margin is 1.625% for 364-Day Tranche Loans and 1.75% for 3-Year Tranche Loans.

The Credit Agreement provides for a ticking fee payable by APA at a rate of 0.225% per annum on the daily average undrawn aggregate commitments thereunder; the ticking fee accrues during the period beginning on the date that is 90 days after January 3, 2024 to the earlier of (i) termination or expiration of the commitments or (ii) the Closing Date.

APA is subject to representations and warranties, covenants, and events of default under the Credit Agreement substantially similar to those in APA's existing 2022 Agreements. The Credit Agreement does not permit lenders to accelerate maturity based on unspecified material adverse changes and does not have prepayment obligations in the event of a decline in credit ratings.

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, 2023, the Company had contractual obligations totaling $1.7 billion, of which $956 million is related to U.S. firm transportation contracts, $614 million is related to the merged concession agreement with the EGPC, and $135 million is related to other items. Under terms agreed to in the Egypt modernized PSC, the Company committed to spend a minimum of $3.5 billion on exploration, development, and operating activities by March 31, 2026. As of December 31, 2023, the Company has spent $2.9 billion and believes it will be able to satisfy the remaining obligation within its current exploration and development program.

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, 2023, the Company had net undiscounted minimum commitments of $346 million and $41 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, 2023 are approximately $3.9 billion.

For additional information regarding these obligations, refer to Note 9—Debt and Financing Costs and Note 11—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 or pension or postretirement benefit obligations, refer to Notes 8—Asset Retirement Obligation and Note 12—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 $5 million for environmental remediation and approximately $83 million for various contingent legal liabilities. For a detailed discussion of the Company's environmental and legal contingencies and other commitments, please see Note 11—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 Mexico, 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 Mexico 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 Mexico 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 Mexico 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 Mexico (GOM) 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 GOM 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 GOM Shelf operations and properties and its GOM operating subsidiary, GOM Shelf LLC (GOM Shelf) to Fieldwood Energy LLC (Fieldwood). Under the terms of the purchase agreement, Apache received cash consideration of $3.75 billion and 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 GOM Assets). In respect of such abandonment obligations, Fieldwood posted letters of credit in favor of Apache (Letters of Credit) and established trust accounts (Trust A and Trust B) of which Apache was a beneficiary and which were funded by two net profits interests (NPIs) depending on future oil prices. On February 14, 2018, Fieldwood filed for protection under Chapter 11 of the U.S. Bankruptcy Code. In connection with the 2018 bankruptcy, Fieldwood confirmed a plan under which Apache agreed, inter alia, to (i) accept bonds in exchange for certain of the Letters of Credit and (ii) amend the Trust A trust agreement and one of the NPIs to consolidate the trusts into a single Trust (Trust A) funded by both remaining NPIs. Following the 2018 reorganization of Fieldwood, Apache held two bonds (Bonds) and five Letters of Credit securing Fieldwood's asset retirement obligations on the Legacy GOM Assets as and when Apache is required to perform or pay for decommissioning any Legacy GOM Asset over the remaining life of the Legacy GOM Assets.

On August 3, 2020, Fieldwood again filed for protection under Chapter 11 of the U.S. Bankruptcy Code. On June 25, 2021, the United States Bankruptcy Court for the Southern District of Texas (Houston Division) entered an order confirming Fieldwood's bankruptcy plan. On August 27, 2021, Fieldwood's bankruptcy plan became effective. Pursuant to the plan, the Legacy GOM 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 GOM Assets will be used to fund the operation of GOM Shelf and the decommissioning of Legacy GOM Assets.

By letter dated April 5, 2022, replacing two prior letters dated September 8, 2021 and February 22, 2022, 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 is currently obligated to perform on certain of the Legacy GOM Assets. As a result, Apache and other current and former owners in these assets have received orders from BSEE to decommission certain of the Legacy GOM Assets included in GOM Shelf's notifications to BSEE. Apache expects to receive similar orders on the other Legacy GOM Assets included in GOM Shelf's notification letters. Apache has also received orders to decommission other Legacy GOM 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 GOM Assets.

As of December 31, 2023, Apache has incurred $819 million in decommissioning costs related to Legacy GOM Assets. GOM Shelf did not, and has confirmed that it will not, reimburse Apache for these decommissioning costs. As a result, Apache has sought and will continue to seek reimbursement from its security for these costs. As of December 31, 2023, $293 million has been reimbursed from Trust A and $336 million has been reimbursed from the Letters of Credit. If GOM Shelf does not reimburse Apache for further decommissioning costs incurred with respect to Legacy GOM Assets, then Apache will continue to seek reimbursement from Trust A, to the extent of available funds, and thereafter, will seek reimbursement from the Bonds and the Letters of Credit until all such funds and securities are fully utilized. In addition, after such sources have been exhausted, Apache has agreed to provide a standby loan to GOM Shelf of up to $400 million to perform decommissioning (Standby Loan Agreement), with such standby loan secured by a first and prior lien on the Legacy GOM Assets.

If the combination of GOM Shelf's net cash flow from its producing properties, the Trust A funds, the Bonds, and the remaining Letters of Credit are insufficient to fully fund decommissioning of any Legacy GOM Assets that Apache may be required to perform or fund, or if GOM Shelf's net cash flow from its remaining producing properties after the Trust A funds, Bonds, and Letters of Credit are exhausted is insufficient to repay any loans made by Apache under the Standby Loan Agreement, then Apache may be forced to use its available cash to fund the deficit.

As of December 31, 2023, Apache estimates that its potential liability to fund the remaining decommissioning of Legacy GOM Assets it may be ordered to perform or fund ranges from $824 million 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 has recorded a contingent liability of $824 million as of December 31, 2023, representing the estimated costs of decommissioning it may be required to perform or fund on Legacy GOM Assets. Of the total liability recorded, $764 million is reflected under the caption "Decommissioning contingency for sold Gulf of Mexico properties," and $60 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 decommissioning rig spread rates, lift boat rates, and planned abandonment logistics could result in a liability in excess of the amount accrued.

As of December 31, 2023, the Company has also recorded a $199 million asset, which represents the remaining amount the Company expects to be reimbursed from the Trust A funds, the Bonds, and the Letters of Credit for decommissioning it may be required to perform on Legacy GOM Assets. Of the total asset recorded, $21 million is reflected under the caption "Decommissioning security for sold Gulf of Mexico properties," and $178 million is reflected under "Other current assets."

The Company recognized $212 million, $157 million, and $446 million during 2023, 2022, and 2021, respectively, of "Losses on previously sold Gulf of Mexico properties" to reflect the net impact of changes to the estimated decommissioning liability and decommissioning asset to the Company's statement of consolidated operations.

On June 21, 2023, the two sureties that issued bonds directly to Apache and two sureties that issued bonds to the issuing bank on the Letters of Credit filed suit against Apache in a case styled *Zurich American Insurance Company, HCC International Insurance Company PLC, Philadelphia Indemnity Insurance Company and Everest Reinsurance Company (Insurers) v. Apache Corporation*, Cause No. 2023-38238 in the 281st Judicial District Court, Harris County Texas. Insurers are seeking to prevent Apache from drawing on the Bonds and Letters of Credit and further allege that they are discharged from their reimbursement obligations related to decommissioning costs and are entitled to other relief. On July 20, 2023, the 281st Judicial District Court denied the Insurers' request for a temporary injunction. On July 26, 2023, Apache removed the suit to the United States Bankruptcy Court for the Southern District of Texas (Houston Division) which subsequently held that the sureties' state court lawsuit violated the terms of the Bankruptcy Confirmation Order and is void. Apache has drawn down the entirety of the Letters of Credit and is vigorously pursuing its claims against the sureties.

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 Mexico named windstorm and business interruption. 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.

The Company purchases multi-year political risk insurance from The Islamic Corporation for the Insurance of Investment and Export Credit Trade (ICIEC, an agency of the Islamic Development Bank) and highly-rated insurers covering a portion of its investments in Egypt for losses arising from confiscation, nationalization, and expropriation risks. In the aggregate, these insurance policies provide up to $750 million of coverage, subject to policy terms and conditions and a retention of approximately $500 million.

Apache also has an insurance policy with U.S. International Development Finance Corporation (DFC), which, subject to policy terms and conditions, provides up to $150 million of coverage through 2024 for losses arising from (1) non-payment by EGPC of arbitral awards covering amounts owed Apache on past due invoices and (2) expropriation of exportable petroleum in the event that actions taken by the government of Egypt prevent Apache from exporting its share of production. The Multilateral Investment Guarantee Agency (MIGA), a member of the World Bank Group, provides $60 million in reinsurance to DFC.

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

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.

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 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 18—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.

Oil and Gas Exploration Costs

The Company accounts for its exploration and production activities using the successful efforts method of accounting. Costs of acquiring unproved and proved oil and gas leasehold acreage are capitalized. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are also capitalized. Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. Costs associated with drilling an exploratory well are initially capitalized, or suspended, pending a determination as to whether proved reserves have been found. On a quarterly basis, management reviews the status of all suspended exploratory well costs in light of ongoing exploration activities and determines 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 recorded as dry hole expense and reported in exploration expense in the statement of consolidated operations. Otherwise, the costs of exploratory wells remain capitalized.

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 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements in Part IV, Item 5 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 Mexico. 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, safety, and public relations 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).

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 associated with the conflict in Ukraine, the recent conflict in Israel and Gaza, 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 19 percent to $80.72 per barrel in 2023 from $99.11 per barrel in 2022. The Company’s average natural gas price realizations decreased 42 percent to $2.91 per Mcf in 2023 from $4.98 per Mcf in 2022. The Company’s average NGL price realizations decreased 38 percent to $21.54 per barrel in 2023 from $34.51 per barrel in 2022. Based on average daily production for 2023, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $74 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 $30 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 $23 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, 2023, the Company had open natural gas derivatives not designated as cash flow hedges in an asset position with a fair value of $6 million. A 10 percent increase in natural gas prices would decrease the asset by approximately $1 million, while a 10 percent decrease in prices would increase the asset by approximately $1 million. These fair value changes assume volatility based on prevailing market parameters as of December 31, 2023. 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

At December 31, 2023, the Company had $4.8 billion, net, in outstanding notes and debentures, all of which was fixed-rate debt, with a weighted average interest rate of 5.34 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 syndicated credit facilities. As of December 31, 2023, the Company had approximately $87 million in cash and cash equivalents, approximately 85 percent of which was invested in money market funds and short-term investments with major financial institutions. As of December 31, 2023, there were $372 million of borrowings outstanding under the Company’s syndicated revolving credit facilities. Changes in the interest rate applicable to short-term investments and credit facility borrowings 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” 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 of $3 million would result from a 10 percent weakening or strengthening, respectively, in the British pound as of December 31, 2023.

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-64 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, 2023, 2022, and 2021, 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 Stephen J. Riney, the Company’s 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, 2023, 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 our management, including our 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 our internal controls over financial reporting during the quarter ended December 31, 2023, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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

During the three months ended December 31, 2023, none of the Company's directors or officers adopted, modified, or terminated a "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement" as each term is defined under Item 408 of Regulation S-K.

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,” and “Corporate Governance—Standing Committees and Meetings of the Board” in the proxy statement relating to the Company’s 2024 annual meeting of shareholders (the Proxy Statement) is incorporated herein by reference.

Code of Business Conduct

In accordance with Rule 5610 of the Nasdaq, the Company maintains a code of business conduct and ethics for its directors, officers, and employees. The Company’s Code of Business Conduct and Ethics was adopted by the Company’s Board of Directors in March 2021 and subsequently amended in September 2021 (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,” “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,” “Option Awards,” 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

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.
2.1	Agreement and Plan of Merger, dated as of March 1, 2021, by and among Apache Corporation, Registrant, and APA Merger Sub, Inc.	8-K12B	2.1	3/1/2021	001-40144
2.2	Agreement and Plan of Merger, dated as of January 3, 2024, by and among Registrant, Astro Comet Merger Sub Corp., and Callon Petroleum Company.	8-K	2.1	1/4/2024	001-40144
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 the Registrant.	8-K12B	4.2	3/1/2021	001-40144
10.1	Credit Agreement [USD Facility], dated as of April 29, 2022, among APA Corporation, 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	5/2/2022	001-40144
10.2	Credit Agreement [GBP Facility], dated as of April 29, 2022, among APA Corporation, 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	5/2/2022	001-40144
10.3	Credit Agreement, dated as of January 30, 2024, among APA Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents party thereto.	8-K	10.1	1/30/2024	001-40144
†10.4	APA Corporation Income Continuance Plan, as amended and restated effective as of March 1, 2021.	8-K12B	10.2	3/1/2021	001-40144
†10.5	APA Corporation Executive Termination Policy, as amended and restated effective as of March 1, 2021.	8-K12B	10.3	3/1/2021	001-40144
†10.6	APA Corporation 2016 Omnibus Compensation Plan, dated February 3, 2016, effective May 12, 2016.	8-K	10.1	5/16/2016	001-04300
†10.7	First Amendment to the Registrant's 2016 Omnibus Compensation Plan, dated July 29, 2019.	10-K	10.13	2/28/2020	001-04300
†10.8	Second Amendment to the Registrant's 2016 Omnibus Compensation Plan, dated March 1, 2021.	8-K12B	10.6	3/1/2021	001-40144
†10.9	APA Corporation 2011 Omnibus Equity Compensation Plan, as amended and restated May 12, 2016.	10-Q	10.1	8/4/2016	001-04300
†10.10	First Amendment to the Registrant's 2011 Omnibus Equity Compensation Plan, dated July 29, 2019.	10-K	10.15	2/28/2020	001-04300
†10.11	Second Amendment to the Registrant's 2011 Omnibus Equity Compensation Plan, dated March 1, 2021.	8-K12B	10.5	3/1/2021	001-40144
†10.12	APA Corporation Deferred Delivery Plan, as amended and restated May 12, 2016.	10-Q	10.3	8/4/2016	001-04300
†10.13	APA Corporation Non-Employee Directors' Compensation Plan, as amended and restated September 12, 2023.	10-Q	10.1	11/2/2023	001-40144
†10.14	APA Corporation Outside Directors' Retirement Plan, as amended and restated July 16, 2014, effective June 30, 2014.	10-Q	10.5	8/8/2014	001-04300
†10.15	APA Corporation Non-Employee Directors' Restricted Stock Units Program, as amended and restated May 14, 2015, pursuant to the Registrant's 2011 Omnibus Equity Compensation Plan.	10-Q	10.6	8/7/2015	001-04300
†10.16	APA Corporation Non-Employee Directors' Restricted Stock Units Program, effective May 12, 2016, pursuant to the Registrant's 2016 Omnibus Compensation Plan.	10-Q	10.4	8/4/2016	001-04300

EXHIBIT NO.	DESCRIPTION	Incorporated by Reference			
		Form	Exhibit	Filing Date	SEC File No.
†10.17	APA Corporation Outside Directors' Deferral Program, effective May 12, 2016, pursuant to the Registrant's 2016 Omnibus Compensation Plan.	10-Q	10.5	8/4/2016	001-04300
†10.18	Amendment of Stock Option Grant Agreement, dated July 29, 2019.	10-K	10.54	2/28/2020	001-04300
†10.19	Form of 2020 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020.	10-K	10.55	2/28/2020	001-04300
†10.20	Form of 2020 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020.	10-K	10.56	2/28/2020	001-04300
†10.21	Form of 2020 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020.	10-K	10.57	2/28/2020	001-04300
†10.22	Form of 2020 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 3, 2020.	10-K	10.58	2/28/2020	001-04300
†10.23	Form of 2021 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021.	10-K	10.43	2/26/2021	001-04300
†10.24	Form of 2021 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021.	10-K	10.44	2/26/2021	001-04300
†10.25	Form of 2021 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021.	10-K	10.45	2/26/2021	001-04300
†10.26	Form of 2021 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 5, 2021.	10-K	10.46	2/26/2021	001-04300
†10.27	Amendment of Restricted Stock Unit Award Agreement, dated March 1, 2021.	8-K12B	10.7	3/1/2021	001-40144
†10.28	Amendment of Performance Share Grant Agreement, dated March 1, 2021.	8-K12B	10.8	3/1/2021	001-40144
†10.29	Amendment of Stock Option Grant Agreement, dated March 1, 2021.	8-K12B	10.9	3/1/2021	001-40144
†10.30	Form of 2022 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.	8-K	10.1	1/7/2022	001-40144
†10.31	Form of 2022 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.	10-K	10.41	2/22/2022	001-40144
†10.32	Form of 2022 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.	10-K	10.42	2/22/2022	001-40144
†10.33	Form of 2022 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2022.	10-K	10.43	2/22/2022	001-40144
†10.34	Amendment of Restricted Stock Unit Award Agreement, dated February 22, 2022.	8-K	10.1	2/23/2022	001-40144
†10.35	Form of 2023 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 4, 2023.	8-K	10.1	1/6/2023	001-40144
†10.36	Form of 2023 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2023.	10-K	10.43	2/23/2023	001-40144
†10.37	Form of 2023 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 4, 2023.	10-K	10.44	2/23/2023	001-40144
†10.38	Form of 2024 Performance Share Program Agreement (2016 Omnibus Compensation Plan), dated January 8, 2024.	8-K	10.1	1/12/2024	001-40144
*†10.39	Form of 2024 Cash-Based Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 8, 2024.				

EXHIBIT NO.	DESCRIPTION	Incorporated by Reference Form	Exhibit	Filing Date	SEC File No.
*†10.40	Form of 2024 Restricted Stock Unit Award Agreement (2016 Omnibus Compensation Plan), dated January 8, 2024.				
*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	APA Corporation Executive Compensation Clawback Policy.				
*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 22, 2024

POWER OF ATTORNEY

The officers and directors of APA Corporation, whose signatures appear below, hereby constitute and appoint John J. Christmann IV, Stephen J. Riney, and Rebecca A. Hoyt, 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 22, 2024
/s/ Stephen J. Riney Stephen J. Riney	President and Chief Financial Officer (principal financial officer)	February 22, 2024
/s/ Rebecca A. Hoyt Rebecca A. Hoyt	Senior Vice President, Chief Accounting Officer, and Controller (principal accounting officer)	February 22, 2024
/s/ Annell R. Bay Annell R. Bay	Director	February 22, 2024
/s/ Juliet S. Ellis Juliet S. Ellis	Director	February 22, 2024
/s/ Charles W. Hooper Charles W. Hooper	Director	February 22, 2024
/s/ Chansoo Joung Chansoo Joung	Director	February 22, 2024
/s/ H. Lamar McKay H. Lamar McKay	Independent, Non-Executive Chair of the Board and Director	February 22, 2024
/s/ Amy H. Nelson Amy H. Nelson	Director	February 22, 2024
/s/ Daniel W. Rabun Daniel W. Rabun	Director	February 22, 2024
/s/ Peter A. Ragauss Peter A. Ragauss	Director	February 22, 2024
/s/ David L. Stover David L. Stover	Director	February 22, 2024

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, 2023. 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, 2023.

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/ Stephen J. Riney
President and Chief Financial Officer
(principal financial officer)

/s/ Rebecca A. Hoyt
Senior Vice President, Chief Accounting Officer and Controller
(principal accounting officer)

Houston, Texas
February 22, 2024

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, 2023, 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, 2023, 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, 2023 and 2022, the related statements of consolidated operations, comprehensive income (loss), cash flows and changes in equity (deficit) and noncontrolling interest for each of the three years in the period ended December 31, 2023, and the related notes and our report dated February 22, 2024 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 22, 2024

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, 2023 and 2022, the related statements of consolidated operations, comprehensive income (loss), cash flows and changes in equity (deficit) and noncontrolling interest for each of the three years in the period ended December 31, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, 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, 2023, 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 22, 2024 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, 2023, the carrying value of the Company's property and equipment was $10,038 million, and depreciation, depletion and amortization (DD&A) expense was $1,540 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 evaluating data used when estimating oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital costs assumptions, and tax rates by jurisdiction, 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, 2023.

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 and the evaluation of management's determination of the inputs described above used by the engineers in estimating oil and gas reserves.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to 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 primarily responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineers used to audit the proved oil and gas reserve estimates for select properties. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating oil and gas reserves by agreeing them to source documentation, and we identified and evaluated corroborative and contrary evidence. We also tested the mathematical accuracy of the DD&A calculation, including comparing the oil and gas reserve amounts used in the calculation to the Company's reserve reports.

	Accounting for asset retirement obligation for the North Sea segment
Description of the Matter	At December 31, 2023, the asset retirement obligation (ARO) balance totaled $2,438 million. As further described in Note 8, 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 obligations. We also tested management's controls over the completeness and accuracy of financial data used in the valuation. 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 recent offshore activities and costs. We also involved our internal specialists in testing the underlying retirement cost estimates.
	Accounting for decommissioning contingency for sold Gulf of Mexico properties
Description of the Matter	At December 31, 2023, the decommissioning contingency for sold Gulf of Mexico properties (decommissioning contingency) balance totaled $824 million. As further described in Note 11, the Company's decommissioning contingency reflects the estimated undiscounted potential liability to fund decommissioning of the sold Gulf of Mexico properties. The estimation of the decommissioning contingency requires significant judgment given the magnitude and higher estimation uncertainty of the expected retirement costs. Auditing the Company's decommissioning contingency is complex and highly judgmental because of the significant estimation required by management in determining the decommissioning contingency. In particular, the estimate was sensitive to retirement cost estimates, which are subjective assumptions 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 decommissioning contingency estimation process, including management's review of the significant assumptions that have a material effect on the determination of the contingency. We also tested management's controls over the completeness and accuracy of financial data used in the valuation. To test the decommissioning contingency, 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 recent offshore activities and costs. 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 22, 2024

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2023	**2022**	**2021**
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil, natural gas, and natural gas liquids production revenues[1]	$ 7,385	$ 9,220	$ 6,498
Purchased oil and gas sales[1]	894	1,855	1,487
Total revenues	8,279	11,075	7,985
Derivative instrument gains (losses), net	99	(114)	94
Gain on divestitures, net	8	1,180	67
Losses on previously sold Gulf of Mexico properties	(212)	(157)	(446)
Other, net	18	148	228
	8,192	12,132	7,928
OPERATING EXPENSES:			
Lease operating expenses[1]	1,436	1,444	1,241
Gathering, processing, and transmission[1]	334	367	264
Purchased oil and gas costs[1]	742	1,776	1,580
Taxes other than income	207	268	204
Exploration	195	305	155
General and administrative	351	483	376
Transaction, reorganization, and separation	15	26	22
Depreciation, depletion, and amortization	1,540	1,233	1,360
Asset retirement obligation accretion	116	117	113
Impairments	61	—	208
Financing costs, net	312	379	514
	5,309	6,398	6,037
NET INCOME BEFORE INCOME TAXES	2,883	5,734	1,891
Current income tax provision	1,338	1,507	652
Deferred income tax provision (benefit)	(1,662)	145	(74)
NET INCOME INCLUDING NONCONTROLLING INTERESTS	3,207	4,082	1,313
Net income attributable to noncontrolling interest – Egypt	352	464	174
Net income attributable to noncontrolling interest – Altus	—	14	4
Net income (loss) attributable to Altus Preferred Unit limited partners	—	(70)	162
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 2,855	$ 3,674	$ 973
NET INCOME PER COMMON SHARE:			
Basic	$ 9.26	$ 11.05	$ 2.60
Diluted	$ 9.25	$ 11.02	$ 2.59
WEIGHTED-AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	308	332	374
Diluted	309	333	375

(1) For related party transactions associated with Kinetik, refer to Note 6—Equity Method Interest for further detail.

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

APA CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)

	For the Year Ended December 31,		
	2023	**2022**	**2021**
		(In millions)	
NET INCOME INCLUDING NONCONTROLLING INTERESTS	$ 3,207	$ 4,082	$ 1,313
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Pension and postretirement benefit plan	1	(8)	7
Share of equity method interests other comprehensive income	—	—	1
COMPREHENSIVE INCOME INCLUDING NONCONTROLLING INTERESTS	3,208	4,074	1,321
Comprehensive income attributable to noncontrolling interest – Egypt	352	464	174
Comprehensive income attributable to noncontrolling interest – Altus	—	14	4
Comprehensive income (loss) attributable to Altus Preferred Unit limited partners	—	(70)	162
COMPREHENSIVE INCOME ATTRIBUTABLE TO COMMON STOCK	$ 2,856	$ 3,666	$ 981

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, 2023	2022	2021
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income including noncontrolling interests	$ 3,207	$ 4,082	$ 1,313
Adjustments to reconcile net income to net cash provided by operating activities:			
Unrealized derivative instrument losses (gains), net	(51)	67	(69)
Gain on divestitures, net	(8)	(1,180)	(67)
Exploratory dry hole expense and unproved leasehold impairments	114	207	97
Depreciation, depletion, and amortization	1,540	1,233	1,360
Asset retirement obligation accretion	116	117	113
Impairments	61	—	208
Provision for (benefit from) deferred income taxes	(1,662)	145	(74)
(Gain) loss from extinguishment of debt	(9)	67	104
Losses on previously sold Gulf of Mexico properties	212	157	446
Other	26	(73)	28
Changes in operating assets and liabilities:			
Receivables	(157)	(93)	(386)
Inventories	13	(1)	(9)
Drilling advances and other current assets	269	(15)	71
Deferred charges and other long-term assets	270	69	(42)
Accounts payable	(84)	(4)	245
Accrued expenses	(400)	303	127
Deferred credits and noncurrent liabilities	(328)	(138)	31
NET CASH PROVIDED BY OPERATING ACTIVITIES	3,129	4,943	3,496
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to upstream oil and gas property	(2,313)	(1,770)	(1,101)
Acquisition of Delaware Basin properties	(24)	(591)	—
Leasehold and property acquisitions	(20)	(37)	(9)
Proceeds from asset divestitures	29	778	256
Proceeds from sale of Kinetik shares	228	224	—
Deconsolidation of Altus cash and cash equivalents	—	(143)	—
Other, net	(38)	28	21
NET CASH USED IN INVESTING ACTIVITIES	(2,138)	(1,511)	(833)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from (payments on) revolving credit facilities, net	(194)	24	392
Payments on Apache fixed-rate debt	(65)	(1,493)	(1,795)
Distributions to noncontrolling interest – Egypt	(238)	(362)	(279)
Dividends paid to APA common stockholders	(308)	(207)	(52)
Treasury stock activity, net	(329)	(1,423)	(847)
Other, net	(15)	(28)	(42)
NET CASH USED IN FINANCING ACTIVITIES	(1,149)	(3,489)	(2,623)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(158)	(57)	40
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	245	302	262
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 87	$ 245	$ 302
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$ 329	$ 322	$ 442
Income taxes paid, net of refunds	1,271	1,431	633

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

APA CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31, 2023		December 31, 2022	
	(In millions, except share data)			
ASSETS				
CURRENT ASSETS:				
Cash and cash equivalents	$	87	$	245
Receivables, net of allowance of $114 and $117		1,610		1,466
Other current assets (Note 5)		765		997
		2,462		2,708
PROPERTY AND EQUIPMENT:				
Oil and gas properties, on the basis of successful efforts accounting:		44,860		42,356
Gathering, processing, and transmission facilities		448		449
Other		634		613
Less: Accumulated depreciation, depletion, and amortization		(35,904)		(34,406)
		10,038		9,012
OTHER ASSETS:				
Equity method interests (Note 6)		437		624
Decommissioning security for sold Gulf of Mexico properties (Note 11)		21		217
Deferred tax asset (Note 10)		1,758		39
Deferred charges and other		528		547
	$	15,244	$	13,147
LIABILITIES, NONCONTROLLING INTEREST, AND EQUITY				
CURRENT LIABILITIES:				
Accounts payable	$	658	$	771
Current debt		2		2
Other current liabilities (Note 7)		1,744		2,143
		2,404		2,916
LONG-TERM DEBT (Note 9)		5,186		5,451
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:				
Deferred tax liability (Note 10)		371		314
Asset retirement obligation (Note 8)		2,362		1,940
Decommissioning contingency for sold Gulf of Mexico properties (Note 11)		764		738
Other		466		443
		3,963		3,435
EQUITY:				
Common stock, $0.625 par, 860,000,000 shares authorized, 420,595,901 and 419,869,987 shares issued, respectively		263		262
Paid-in capital		11,126		11,420
Accumulated deficit		(2,959)		(5,814)
Treasury stock, at cost, 117,020,000 and 108,310,838 shares, respectively		(5,790)		(5,459)
Accumulated other comprehensive income		15		14
APA SHAREHOLDERS' EQUITY		2,655		423
Noncontrolling interest – Egypt		1,036		922
TOTAL EQUITY		3,691		1,345
	$	15,244	$	13,147

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

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

	Redeemable Noncontrolling Interest - Altus Preferred Unit Limited Partners	Common Stock	Paid-In Capital	Accumulated Deficit	Treasury Stock	Accumulated Other Comprehensive Income	APA SHAREHOLDERS' EQUITY (DEFICIT)	Noncontrolling Interests	TOTAL EQUITY (DEFICIT)
					(In millions)				
BALANCE AT DECEMBER 31, 2020	$ 608	$ 262	$11,735	$ (10,461)	$ (3,189)	$ 14	$ (1,639)	$ 994	$ (645)
Net income attributable to common stock	—	—	—	973	—	—	973	—	973
Net income attributable to noncontrolling interest – Egypt	—	—	—	—	—	—	—	174	174
Net income attributable to noncontrolling interest – Altus	—	—	—	—	—	—	—	4	4
Net income attributable to Altus Preferred Unit limited partners	162	—	—	—	—	—	—	—	—
Distributions payable to Altus Preferred Unit limited partners	(12)	—	—	—	—	—	—	—	—
Distributions paid to Altus Preferred Unit limited partners	(46)	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest – Egypt	—	—	—	—	—	—	—	(279)	(279)
Common dividends ($0.2375 per share)	—	—	(87)	—	—	—	(87)	—	(87)
Common stock activity, net	—	—	(6)	—	—	—	(6)	—	(6)
Treasury stock activity, net	—	—	—	—	(847)	—	(847)	—	(847)
Compensation expense	—	—	21	—	—	—	21	—	21
Other	—	—	(18)	—	—	8	(10)	(15)	(25)
BALANCE AT DECEMBER 31, 2021	$ 712	$ 262	$11,645	$ (9,488)	$ (4,036)	$ 22	$ (1,595)	$ 878	$ (717)
Net income attributable to common stock	—	—	—	3,674	—	—	3,674	—	3,674
Net income attributable to noncontrolling interest – Egypt	—	—	—	—	—	—	—	464	464
Net income attributable to noncontrolling interest – Altus	—	—	—	—	—	—	—	14	14
Net loss attributable to Altus Preferred Unit limited partners	(70)	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest – Egypt	—	—	—	—	—	—	—	(362)	(362)
Common dividends ($0.75 per share)	—	—	(245)	—	—	—	(245)	—	(245)
Common stock activity, net	—	—	(6)	—	—	—	(6)	—	(6)
Deconsolidation of Altus	(642)	—	—	—	—	—	—	(72)	(72)
Treasury stock activity, net	—	—	—	—	(1,423)	—	(1,423)	—	(1,423)
Compensation expense	—	—	26	—	—	—	26	—	26
Other	—	—	—	—	—	(8)	(8)	—	(8)
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 – Egypt	—	—	—	—	—	—	—	352	352
Distributions to noncontrolling interest – Egypt	—	—	—	—	—	—	—	(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

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 natural gas, crude oil, and natural gas liquids. The Company's upstream 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 exploration and appraisal operations ongoing in Suriname, as well as interests in Uruguay and other international locations that may, over time, result in reportable discoveries and development opportunities. Prior to the BCP Business Combination defined below, the Company's midstream business was operated by Altus Midstream Company (ALTM) through its subsidiary Altus Midstream LP (collectively, Altus).

On March 1, 2021, Apache Corporation, the Company's predecessor registrant, consummated a holding company reorganization (the Holding Company Reorganization), pursuant to which Apache Corporation became a direct, wholly owned subsidiary of APA Corporation, and all of Apache Corporation's outstanding shares automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to Apache Corporation pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache Corporation as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized the Company's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have subsidiaries operating around the globe. As a holding company, APA Corporation's primary assets are its ownership interests in its subsidiaries.

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 implementation of the Holding Company Reorganization was accounted for as a merger under common control. APA recognized the assets and liabilities of Apache at carryover basis. The consolidated financial statements of APA present comparative information for prior years on a combined basis, as if both APA and Apache were under common control for all periods presented.

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.

Noncontrolling interests represent third-party ownership in the net assets of a consolidated subsidiary of APA and are reflected separately in the Company's financial statements. 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.

Additionally, prior to the BCP Business Combination (as defined below), third-party investors owned a minority interest of approximately 21 percent of Altus, which was reflected as a separate noncontrolling interest component of equity in the Company's consolidated balance sheet. ALTM qualified as a VIE under GAAP, which APA consolidated because a wholly owned subsidiary of APA had a controlling financial interest and was determined to be the primary beneficiary.

On February 22, 2022, ALTM closed a transaction to combine with privately owned BCP Raptor Holdco LP (BCP and, together with BCP Raptor Holdco GP, LLC, the Contributed Entities) in an all-stock transaction, pursuant to the Contribution Agreement entered into by and among ALTM, Altus Midstream LP, New BCP Raptor Holdco, LLC (the Contributor), and BCP (the BCP Contribution Agreement). Pursuant to the BCP Contribution Agreement, the Contributor contributed all of the equity interests of the Contributed Entities (the Contributed Interests) to Altus Midstream LP, with each Contributed Entity becoming a wholly owned subsidiary of Altus Midstream LP (the BCP Business Combination). Upon closing the transaction, the combined entity was renamed Kinetik Holdings Inc. (Kinetik), and the Company determined that it was no longer the primary beneficiary of Kinetik. The Company further determined that Kinetik no longer qualified as a VIE under GAAP. As a result, the Company deconsolidated ALTM on February 22, 2022. Refer to Note 2—Acquisitions and Divestitures for further detail.

During each of the years ended December 31, 2023 and 2022, the Company had a designated director on the Kinetik board of directors. As a result, the Company is considered to have had significant influence over Kinetik for all periods presented and will continue to have such influence until such time as Kinetik appoints a replacement for the Company's designated director, given that the Company's current beneficial ownership percentage in Kinetik no longer entitles it to designate a director to the Kinetik board.

Investments in which the Company has significant influence, but not control, are accounted for under the equity method of accounting. These investments are recorded separately as "Equity method interests" in the Company's consolidated balance sheet. The Company elected the fair value option to account for its equity method interest in Kinetik. Refer to Note 6—Equity Method Interests for further detail.

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 fair value of equity method interests (refer to "Equity Method Interests" within this Note 1 below and Note 6—Equity Method Interests), the assessment of asset retirement obligations (refer to Note 8—Asset Retirement Obligation), the estimate of income taxes (refer to Note 10—Income Taxes), the estimation of the contingent liability representing Apache's potential decommissioning obligations on sold properties in the Gulf of Mexico (refer to Note 11—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 18—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 6—Equity Method Interests, Note 9—Debt and Financing Costs, Note 12—Retirement and Deferred Compensation Plans, and Note 13—Redeemable Noncontrolling Interest — Altus 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.

For the years ended December 31, 2023 and 2022, the Company recorded $11 million and no asset impairments, respectively, in connection with fair value assessments. For the year ended December 31, 2021, the Company recorded asset impairments totaling $208 million. These charges include a $160 million impairment on the Company's equity method interest in a pipeline investment as part of Altus' review of the fair value of its assets in relation to the BCP Business Combination. Refer to "Equity Method Interests" within this Note 1 below and Note 2—Acquisitions and Divestitures for further detail on the BCP Business Combination.

Revenue Recognition

Upstream

The Company's upstream 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 17—Business Segment Information for a disaggregation of revenue by product and reporting segment.

Altus Midstream

Prior to the deconsolidation of Altus on February 22, 2022, the Company's Altus Midstream segment was operated by ALTM, through its subsidiary, Altus Midstream LP. Altus generated revenue from contracts with customers from its gathering, compression, processing, and transmission services provided on the Company's natural gas and natural gas liquid production volumes. Under these long-term commercial service contracts, providing the related service represented a single, distinct performance obligation on behalf of Altus that was satisfied over time. In accordance with the terms of these agreements, Altus primarily received a fixed fee for each contract year, subject to yearly fee escalation recalculations. Revenue was primarily measured using the output method and recognized in the amount to which Altus had the right to invoice, as performance completed to date corresponded directly with the value to its customers. For the periods prior to the BCP Business Combination, Altus Midstream segment revenues were primarily attributable to sales between Altus and Apache, which were fully eliminated upon consolidation.

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 $1.5 billion and $1.3 billion as of December 31, 2023 and 2022, 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. Over the past year, the Company experienced a gradual decline in the timeliness of receipts from the EGPC for the Company's Egyptian oil and gas sales. Although the Company continues to receive periodic payments from EGPC, deteriorating economic conditions in Egypt have lessened the availability of U.S. dollars in Egypt, resulting in a delay in receipts from EGPC. Continuation of the currency shortage in Egypt could lead to further delays, deferrals of payment, or non-payment in the future; however, the Company currently anticipates that it will ultimately be able to collect its receivable from EGPC.

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, 2023 and 2022, the Company had $87 million and $245 million, respectively, of cash and cash equivalents. The Company had no restricted cash as of December 31, 2023 and 2022.

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,		
	2023	2022	2021
		(In millions)	
Allowance for credit loss at beginning of year	$ 117	$ 109	$ 95
Additional provisions for the year	16	9	19
Uncollectible accounts written off, net of recoveries	(19)	(1)	(5)
Allowance for credit loss at end of year	$ 114	$ 117	$ 109

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 2023, the Company recorded $50 million of impairments in connection with valuations of drilling and operations equipment inventory upon the Company's decision to suspend drilling operations in the North Sea.

The Company also recorded other impairments during 2021 of approximately $26 million in connection with inventory valuations in Egypt and $22 million in connection with inventory valuations and expected equipment dispositions 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 unproved properties:

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Unproved properties:			
U.S.	$ 10	$ 20	$ 22
Egypt	—	4	8
North Sea	11	—	1
Other International	1	—	—
Total unproved properties	$ 22	$ 24	$ 31

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.

For the years ended December 31, 2023, 2022, and 2021, 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 $448 million and $449 million at December 31, 2023 and 2022, respectively, with accumulated depreciation for these assets totaling $373 million and $367 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.

The Company assesses the carrying amount of its GPT facilities whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the carrying amount of these facilities is more than the sum of the undiscounted cash flows, an impairment loss is recognized for the excess of the carrying value over its fair value.

For the years ended December 31, 2023, 2022, and 2021, 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 $217 million and $206 million at December 31, 2023 and 2022, respectively.

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, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity method affiliates 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.

Equity Method Interests

The Company follows the equity method of accounting when it does not exercise control over its equity interests, but can exercise significant influence over the operating and financial policies of the entity. Under this method, the equity interests are carried originally at acquisition cost, increased by the Company's proportionate share of the equity interest's net income and contributions made by the Company, and decreased by the Company's proportionate share of the equity interest's net losses and distributions received by the Company. Refer to Note 6—Equity Method Interests for further details of the Company's equity method interests.

Equity method interests are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, if the loss is deemed to be other than temporary. When the loss is deemed to be other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income. Prior to the deconsolidation of Altus on February 22, 2022, in the fourth quarter of 2021, Altus, as part of its review of the fair value of its assets in relation to the BCP Business Combination, determined the fair value of a pipeline investment was below carrying value. As such, in the fourth quarter of 2021, Altus recorded an impairment charge of $160 million on its equity method interest in the pipeline.

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 11—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 10—Income Taxes for further information.

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. Prior to the deconsolidation of Altus on February 22, 2022, the Company used the "if-converted method" to determine the potential dilutive effect of an assumed exchange of the outstanding Preferred Units of Altus Midstream LP for shares of ALTM's common stock. The impact to net income (loss) attributable to common stock on an assumed conversion of the redeemable noncontrolling Preferred Units interest in Altus Midstream LP was anti-dilutive for the year ended December 31, 2021.

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 14—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 2023, 2022, and 2021 totaling $15 million, $26 million, and $22 million, respectively, including $7 million, $15 million, and $17 million, respectively, related to ongoing consulting and separation costs in international operations associated with the redesign of the Company's organizational structure and operations.

New Pronouncements Issued But Not Yet Adopted

In November 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2023-07, "Segment Reporting (Topic 280)," which expands disclosures about a public entity's reportable segments and requires more enhanced information about a reportable segment's expenses, interim segment profit or loss, and how a public entity's chief operating decision maker uses reported segment profit or loss information in assessing segment performance and allocating resources. The amendments do not change or remove existing disclosure requirements or how a public entity identifies its operating segments, aggregates those operating segments, or applies the quantitative thresholds to determine its reportable segments. The amendments are effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted, and the amendments are required to be applied on a retrospective basis. The Company is currently assessing the impact of adopting this standard and does not believe this will have a material impact on its financial statements.

In December 2023, the FASB issued ASU 2023-09 "Improvements to Income Tax Disclosures (Topic 740)," which requires enhanced disclosures primarily related to existing rate reconciliation and income taxes paid information. This update is effective for the Company beginning in the first quarter of 2025 and is applied on a prospective basis. Retrospective application is also permitted. The Company does not believe this will have a material impact on its financial statements.

2. ACQUISITIONS AND DIVESTITURES

2024 Activity

On January 3, 2024, APA and Callon Petroleum Company (Callon) entered into a definitive agreement (the Merger Agreement), pursuant to which APA will acquire Callon in an all-stock transaction valued at approximately $4.5 billion, inclusive of Callon's net debt.

In this all-stock transaction, each eligible outstanding share of Callon common stock will be exchanged for 1.0425 shares of APA common stock, representing an implied value to each Callon share of $38.31 per share based on the closing price of APA common stock on January 3, 2024. After closing, existing APA shareholders are expected to own approximately 81 percent of the combined company, and existing Callon shareholders are expected to own approximately 19 percent of the combined company.

APA expects to retire the existing debt at Callon and replace it with APA's syndicated credit agreement, dated January 30, 2024, under which the lenders have committed an aggregate $2.0 billion for senior unsecured delayed-draw term loans to APA. Refer to Note 9—Debt and Financing Costs for further detail.

The transaction has been unanimously approved by the boards of directors of both APA and Callon and is expected to close during the second quarter of 2024, subject to customary closing conditions, termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, and approval of the transaction by shareholders of both APA and Callon. Upon the closing of the transaction, a representative from Callon will be appointed to the APA board of directors (Board of Directors). APA's executive management team will lead the combined company, with the headquarters remaining in Houston, Texas.

2023 Activity

In December 2023, the Company sold 7.5 million of its shares of Kinetik Class A Common Stock (Kinetik Shares) for cash proceeds of $228 million. Refer to Note 6—Equity Method Interests for further detail.

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

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.

2022 Activity

During the third quarter of 2022, the Company closed on the acquisition of oil and gas assets in the Delaware Basin for a total purchase price of $615 million after post-closing adjustments. Final cash settlements of $24 million were completed during 2023. The Company recorded $581 million for proved properties, $38 million for unproved leasehold, and $4 million for abandonment obligations.

During 2022, the Company completed other leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of approximately $37 million.

During 2022, the Company completed the sale of non-core assets and leasehold in multiple transactions for total cash proceeds of $52 million, recognizing an aggregate gain of approximately $36 million, upon closing of these transactions.

During 2022, the Company completed the sale of certain non-core mineral rights in the Delaware Basin. The Company received total cash proceeds of approximately $726 million after certain post-closing adjustments and recognized an associated gain of approximately $560 million.

The BCP Business Combination was completed on February 22, 2022. As consideration for the contribution of the Contributed Interests, ALTM issued 50 million shares of Class C Common Stock (and Altus Midstream LP issued a corresponding number of common units) to BCP's unitholders, which are principally funds affiliated with Blackstone and I Squared Capital. ALTM's stockholders continued to hold their existing shares of common stock. As a result of the transaction, the Contributor, or its designees, collectively owned approximately 75 percent of the issued and outstanding shares of ALTM common stock. Apache Midstream LLC, a wholly owned subsidiary of APA, which owned approximately 79 percent of the issued and outstanding shares of ALTM common stock prior to the BCP Business Combination, owned approximately 20 percent of the issued and outstanding shares of Kinetik common stock after the transaction closed.

As a result of the BCP Business Combination, the Company deconsolidated ALTM on February 22, 2022 and recognized a gain of approximately $609 million that reflects the difference between the Company's $193 million net effect of deconsolidating ALTM's balance sheet and the $802 million fair value of the Company's approximate 20 percent retained ownership in the combined entity.

During the first quarter of 2022, the Company sold four million of its Kinetik Shares for cash proceeds of $224 million. Refer to Note 6—Equity Method Interests for further detail.

2021 Activity

During the second quarter of 2021, the Company completed the sale of certain non-core assets in the Permian Basin with a net carrying value of $157 million for cash proceeds of $176 million and the assumption of asset retirement obligations of $44 million. The Company recognized a gain of approximately $63 million in connection with the sale.

During 2021, the Company also completed the sale of other non-core assets and leasehold, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $80 million. The Company recognized a gain of approximately $4 million upon closing of these transactions.

During 2021, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $9 million.

3. CAPITALIZED EXPLORATORY WELL COSTS

The following summarizes the changes in capitalized exploratory well costs for the years ended December 31, 2023, 2022, and 2021. 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,		
	2023	2022	2021
		(In millions)	
Capitalized well costs at beginning of year	$ 474	$ 321	$ 197
Additions pending determination of proved reserves	265	287	174
Reclassifications to proved properties	(135)	(110)	(40)
Charged to exploration expense	(18)	(24)	(10)
Capitalized well costs at end of year	$ 586	$ 474	$ 321

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:

	2023	2022	2021
		(In millions)	
Exploratory well costs capitalized for a period of one year or less	$ 156	$ 215	$ 198
Exploratory well costs capitalized for a period greater than one year	430	259	123
Capitalized well costs at end of year	$ 586	$ 474	$ 321
Number of projects with exploratory well costs capitalized for a period greater than one year	33	21	13

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 $430 million at December 31, 2023, with $421 million related to Suriname exploration and appraisal. Detailed engineering and feasibility studies are underway in Block 58 offshore Suriname, and a final investment decision is expected near the end of 2024. In addition, ongoing analysis of well results and appraisal activity is continuing. The remaining projects pertain to onshore drilling activity in Egypt for which continued testing and evaluation is ongoing.

Dry hole expenses from suspended exploratory well costs previously capitalized for greater than one year at December 31, 2022 totaled $16 million. These expenses pertained to projects in the North Sea and Egypt.

The following table summarizes aging by geographic area of those exploratory well costs that, as of December 31, 2023, have been capitalized for a period greater than one year, categorized by the year in which drilling was completed:

	Total	2022	2021	2020 and Prior
		(In millions)		
Suriname	$ 421	$ 178	$ 153	$ 90
Egypt	9	—	—	9
	$ 430	$ 178	$ 153	$ 99

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.

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, 2023, the Company had derivative positions with four 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 or changes in currency exchange rates.

Derivative Instruments

Commodity Derivative Instruments

As of December 31, 2023, 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—June 2024	NYMEX Henry Hub/IF Waha	16,380	$(1.15)	—	—
January—June 2024	NYMEX Henry Hub/IF HSC	—	—	16,380	$(0.10)

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, 2023						
Assets:						
Commodity derivative instruments	$ —	$ 6	$ —	$ 6	$ —	$ 6
December 31, 2022						
Assets:						
Commodity derivative instruments	$ —	$ 5	$ —	$ 5	$ —	$ 5
Liabilities:						
Commodity derivative instruments	$ —	$ 50	$ —	$ 50	$ —	$ 50

(1) The derivative fair values are based on analysis of each contract on a gross basis, excluding the impact of netting agreements with counterparties and reclassifications between long-term and short-term balances.

The fair values of the Company's 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,	
	2023	2022
	(In millions)	
Current Assets: Other current assets	$ 6	$ —
Other Assets: Deferred charges and other	—	5
Total derivative assets	$ 6	$ 5
Current Liabilities: Other current liabilities	$ —	$ 50
Total derivative liabilities	$ —	$ 50

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,		
	2023	2022	2021
		(In millions)	
Realized:			
Commodity derivative instruments	$ 48	$ (34)	$ 25
Foreign currency derivative instruments	—	(13)	—
Realized gains (losses), net	48	(47)	25
Unrealized:			
Commodity derivative instruments	51	(36)	(20)
Pipeline capacity embedded derivatives	—	—	7
Preferred Units embedded derivative	—	(31)	82
Unrealized gains (losses), net	51	(67)	69
Derivative instrument gains (losses), net	$ 99	$ (114)	$ 94

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:

	2023	2022
	(In millions)	
Inventories	$ 453	$ 427
Drilling advances	88	89
Prepaid assets and other	46	31
Current decommissioning security for sold Gulf of Mexico assets	178	450
Total Other current assets	$ 765	$ 997

6. EQUITY METHOD INTERESTS

As of December 31, 2023 and 2022, the Company recorded $437 million and $624 million, respectively, for ownership of its Kinetik Shares. The Company's Kinetik Shares are treated as an interest in equity securities measured at fair value. The Company elected the fair value option for measuring its equity method interest in Kinetik based on practical expedience, variances in reporting timelines, and cost-benefit considerations. The fair value of the Company's interest in Kinetik is determined using observable share prices on a major exchange, a Level 1 fair value measurement. Fair value adjustments are recorded as a component of "Other, net" under "Revenues and other" in the Company's statement of consolidated operations.

The Company's initial interest in Kinetik was measured at fair value based on the Company's ownership of approximately 12.9 million Kinetik Shares as of February 22, 2022. In March 2022, the Company sold four million of its Kinetik Shares for cash proceeds of $224 million. Refer to Note 2—Acquisitions and Divestitures for further detail. During the second quarter of 2022, Kinetik issued a two-for-one split of its common stock, resulting in the Company owning approximately 17.7 million Kinetik Shares. In December 2023, the Company sold 7.5 million of its Kinetik Shares for cash proceeds of $228 million.

The Company has received approximately 2.9 million Kinetik Shares as paid-in-kind dividends through December 31, 2023. As of December 31, 2023, the Company owned 13.1 million Kinetik Shares, representing approximately 9 percent of Kinetik's outstanding common stock.

The Company recorded changes in the fair value of its equity method interest in Kinetik totaling gains of $41 million and $72 million during 2023 and 2022, respectively. The balance of the Company's equity method interest in Kinetik was also impacted by the sales of Kinetik Shares noted above during 2023 and 2022.

The following table represents related party sales and costs associated with Kinetik:

	For the Year Ended December 31,	
	2023	2022
	(In millions)	
Natural gas and NGLs sales	$ 92	$ 18
Purchased oil and gas sales	29	—
	$ 121	$ 18
Gathering, processing, and transmission costs	$ 108	$ 93
Purchased oil and gas costs	80	—
Lease operating expenses	7	—
	$ 195	$ 93

As of December 31, 2023 and 2022, the Company has recorded accrued costs payable to Kinetik of approximately $28 million and $18 million, respectively, and accrued receivables from Kinetik of approximately $16 million and $13 million, respectively.

7. OTHER CURRENT LIABILITIES

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

	2023	2022
	(In millions)	
Accrued operating expenses	$ 162	$ 145
Accrued exploration and development	371	333
Accrued compensation and benefits	390	514
Accrued interest	93	97
Accrued income taxes	138	90
Current asset retirement obligation	76	55
Current operating lease liability	116	167
Current decommissioning contingency for sold Gulf of Mexico properties	60	450
Other	338	292
Total Other current liabilities	$ 1,744	$ 2,143

8. ASSET RETIREMENT OBLIGATION

The following table describes changes to the Company's asset retirement obligation (ARO) liability for the years ended December 31, 2023 and 2022:

	For the Year Ended December 31, 2023	For the Year Ended December 31, 2022
	(In millions)	
Asset retirement obligation at beginning of the year	$ 1,995	$ 2,130
Liabilities incurred	14	4
Liabilities acquired	—	4
Liabilities divested	—	(73)
Liabilities settled	(43)	(39)
Accretion expense	116	117
Revisions in estimated liabilities	356	(148)
Asset retirement obligation at end of the year	2,438	1,995
Less current portion	(76)	(55)
Asset retirement obligation, long-term	$ 2,362	$ 1,940

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 2023 and 2022, the Company recorded $14 million and $4 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 2023, net abandonment costs were revised upward by approximately $356 million, primarily reflecting changes in estimates of timing, activity costs, and foreign currency exchange rates on service costs in the North Sea. During 2022, net abandonment costs were revised downward by approximately $148 million to reflect changes in estimates of timing and foreign currency exchange rates on service costs, primarily in the North Sea, partially offset by an upward revision in the U.S.

9. 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. All indentures of Apache for the notes and debentures described below place certain restrictions on Apache, including limits on Apache's ability to incur debt secured by certain liens. Certain of these indentures also restrict Apache's ability to enter into certain sale and leaseback transactions and give holders the option to require Apache to repurchase outstanding notes and debentures upon certain changes in control. None of the indentures contain prepayment obligations in the event of a decline in credit ratings.

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.

On October 17, 2022, Apache redeemed the outstanding $123 million outstanding principal amount of 2.625% notes due January 15, 2023, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The redemption was financed in part by Apache's borrowing under the Company's U.S. dollar-denominated revolving credit facility.

During 2022, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $15 million for an aggregate purchase price of $16 million in cash, including accrued interest and broker fees, reflecting a premium to par of an aggregate $1 million. The Company recognized a $1 million loss on these repurchases. The repurchases were partially financed by borrowing under Apache's former revolving credit facility.

During 2022, Apache closed cash tender offers for certain outstanding notes issued under its indentures, accepting for purchase $1.1 billion aggregate principal amount of notes. Apache paid holders an aggregate $1.2 billion in cash, reflecting principal, premium to par, and accrued and unpaid interest. The Company recognized a $66 million loss on extinguishment of debt, including $11 million of unamortized debt discount and issuance costs in connection with the note purchases. The repurchases were partially financed by borrowing under Apache's former revolving credit facility.

On January 18, 2022, Apache redeemed the outstanding $213 million principal amount of 3.25% senior notes due April 15, 2022, at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The redemption was financed by borrowing under Apache's former revolving credit facility.

During 2021, Apache closed cash tender offers for certain outstanding notes, accepting for purchase $1.7 billion aggregate principal amount of notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of $1.8 billion, reflecting principal, premium to par, and accrued and unpaid interest. The Company recognized a $105 million loss on extinguishment of debt, including $11 million of unamortized debt discount and issuance costs, in connection with the note purchases.

During 2021, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $22 million for an aggregate purchase price of $20 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $2 million. The Company recognized a $1 million net gain on extinguishment of debt as part of these transactions.

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, 2023 and 2022:

	December 31, 2023	December 31, 2022
	(In millions)	
4.625% notes due 2025[1]	$ 51	$ 51
7.7% notes due 2026	78	78
7.95% notes due 2026	132	132
4.875% due 2027[1]	108	108
4.375% notes due 2028[1]	325	325
7.75% notes due 2029[1][2]	235	235
4.25% notes due 2030[1]	516	579
6.0% notes due 2037[1]	443	443
5.1% notes due 2040[1]	1,333	1,333
5.25% notes due 2042[1]	399	399
4.75% notes due 2043[1]	428	428
4.25% notes due 2044[1]	211	221
7.375% debentures due 2047	150	150
5.35% notes due 2049[1]	387	387
7.625% debentures due 2096	39	39
Apache notes and debentures before unamortized discount and debt issuance costs[3]	4,835	4,908
Syndicated credit facilities[4]	372	566
Apache finance lease obligations	32	34
Unamortized discount	(26)	(27)
Debt issuance costs	(25)	(28)
Total debt	5,188	5,453
Current maturities	(2)	(2)
Long-term debt	$ 5,186	$ 5,451

(1) These notes are redeemable, as a whole or in part, at Apache’s option, subject to a make-whole premium, except that the 7.75% notes due 2029 are only redeemable as whole for principal and accrued interest in the event of certain Canadian tax law changes. The remaining notes and debentures are not redeemable.

(2) Assumed by Apache in August 2017 as permitted by terms of these notes originally issued by a subsidiary and guaranteed by Apache.

(3) The fair values of Apache’s notes and debentures were $4.3 billion and $4.2 billion as of December 31, 2023 and 2022, 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).

(4) 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, 2023 are as follows:

	(In millions)
2024	$ —
2025	51
2026	210
2027	108
2028	325
Thereafter	4,141
Notes and debentures, excluding discounts and debt issuance costs	$ 4,835

Financing Costs, Net

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

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Interest expense	$ 351	$ 332	$ 419
Amortization of debt issuance costs	4	8	8
Capitalized interest	(24)	(18)	(9)
Loss (gain) on extinguishment of debt	(9)	67	104
Interest income	(10)	(10)	(8)
Financing costs, net	$ 312	$ 379	$ 514

Debt issuance costs are charged to financing costs over the life of the related debt issuances. Discount amortization of $1 million, $2 million, and $6 million was recorded as interest expense in 2023, 2022, and 2021, respectively.

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, 2023 and 2022, there were no outstanding borrowings under these facilities. As of December 31, 2023, there were £416 million and $2 million in letters of credit outstanding under these facilities. As of December 31, 2022, there were £199 million and $17 million in letters of credit outstanding under these facilities.

Unsecured 2022 Committed Bank Credit Facilities

On April 29, 2022, the Company entered into two unsecured syndicated credit agreements for general corporate purposes that replaced and refinanced Apache's 2018 unsecured syndicated credit agreement (the Former Facility).

- One agreement is denominated in US dollars (the USD Agreement) and provides for an unsecured five-year revolving credit facility, with aggregate commitments of US$1.8 billion (including a letter of credit subfacility of up to US$750 million, of which US$150 million currently is committed). The Company may increase commitments up to an aggregate US$2.3 billion by adding new lenders or obtaining the consent of any increasing existing lenders. This facility matures in April 2027, subject to the Company's two, one-year extension options.

- The second agreement is denominated in pounds sterling (the 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 April 2027, subject to the Company's two, one-year extension options.

In connection with the Company's entry into the USD Agreement and the GBP Agreement (each, a 2022 Agreement), Apache terminated US$4.0 billion of commitments under the Former Facility, borrowings then outstanding under the Former Facility were deemed outstanding under the USD Agreement, and letters of credit then outstanding under the Former Facility were deemed outstanding under a 2022 Agreement, depending upon whether denominated in US dollars or pounds sterling. Apache may borrow under the USD Agreement up to an aggregate principal amount of US$300 million outstanding at any given time. Apache has guaranteed obligations under each 2022 Agreement effective until the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures is less than US$1.0 billion.

As of December 31, 2023, there were $372 million of borrowings under the USD Agreement and an aggregate £348 million in letters of credit outstanding under the GBP Agreement. As of December 31, 2023, there were no letters of credit outstanding under the USD Agreement. As of December 31, 2022, there were $566 million of borrowings and a $20 million letter of credit outstanding under the USD Agreement, and an aggregate £652 million in letters of credit outstanding under the GBP Agreement. The letters of credit denominated in pounds were issued to support North Sea decommissioning obligations, the terms of which require such support while Apache's credit rating by Standard & Poor's remains below BBB; on March 26, 2020, Standard & Poor's reduced Apache's rating from BBB to BB+, which was affirmed in 2023.

All borrowings under the 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 ranging from 0.10% to 0.675% (Base Rate Margin), or an adjusted term SOFR rate (as defined), plus a margin varying from 1.10% to 1.675% (Applicable Margin). All borrowings under the GBP Agreement bear interest at an adjusted rate per annum determined by reference to the Sterling Overnight Index Average published by the Bank of England, plus the Applicable Margin. Each 2022 Agreement also requires the borrower to pay quarterly a facility fee on total commitments. 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, or if such indebtedness is not rated and the Apache guaranty is in effect, of Apache (Long-Term Debt Rating). As of December 31, 2023, Apache's Long-Term Debt Rating applied, and the Base Rate Margin was 0.40%, the Applicable Margin was 1.40%, and the facility fee was 0.225%.

A commission is payable quarterly to lenders under each 2022 Agreement 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.

Borrowers under each 2022 Agreement, which may 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 substantially similar to those in the Former Facility, such as:

- A financial covenant requires APA to maintain an adjusted debt-to-capital ratio of not greater than 60 percent at the end of any fiscal quarter. For purposes of this calculation, capital continues to exclude the effects of non-cash write-downs, impairments, and related charges occurring after June 30, 2015. At December 31, 2023, APA's debt-to-capital ratio as calculated under each 2022 Agreement was 20 percent.

- A negative covenant restricts the ability of APA and its subsidiaries to create liens securing debt on their hydrocarbon-related assets, with exceptions for liens typically arising in the oil and gas industry; liens securing debt incurred to finance the acquisition, construction, improvement, or capital lease of assets, provided that such debt, when incurred, does not exceed the subject purchase price and costs, as applicable, and related expenses; liens on subsidiary assets located outside of the U. S. and Canada; and liens arising as a matter of law, such as tax and mechanics' liens. Liens on assets also are permitted if debt secured thereby does not exceed 15 percent of APA's consolidated net tangible assets or approximately $1.9 billion as of December 31, 2023.

- 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.

Consistent with the Former Facility, the 2022 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 each 2022 Agreement as of December 31, 2023.

Commercial Paper Program

On December 13, 2023, the Company established 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 (the CP Notes) up to a maximum aggregate face amount of $1.8 billion outstanding at any time. The Company intends to use net proceeds of the CP Notes for general corporate purposes.

Payment of the CP Notes has been 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 is less than US$1.0 billion.

The CP Notes will be 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. The maturities of the CP Notes may vary but may not exceed 397 days from the date of issuance.

As of December 31, 2023, the Company had not issued any CP Notes.

Subsequent Event

On January 30, 2024, APA entered into a syndicated credit agreement under which the lenders have committed an aggregate $2.0 billion for senior unsecured delayed-draw term loans to APA (Credit Agreement). Subject to satisfaction of certain limited conditions, APA may borrow under the Credit Agreement to refinance certain indebtedness of Callon, upon or after closing of APA's pending acquisition of Callon. Refer to Note 2—Acquisitions and Divestitures for further detail.

Two tranches of term loans would be available to APA for borrowing only on the date of closing of transactions under the Merger Agreement and satisfaction of certain other conditions under the Credit Agreement (Closing Date); of the aggregate $2.0 billion in commitments, $1.5 billion is for term loans that would mature three years after the Closing Date (3-Year Tranche Loans) and $500 million is for term loans that would mature 364 days after the Closing Date (364-Day Tranche Loans).

Indebtedness of Callon that APA could refinance by borrowing under the Credit Agreement on the Closing Date includes indebtedness outstanding under (i) the Amended and Restated Credit Agreement, dated October 19, 2022, among Callon, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (Callon Credit Agreement), (ii) Callon's 6.375% Senior Notes due 2026 (Callon's 2026 Notes), (iii) Callon's 8.00% Senior Notes due 2028 (Callon's 2028 Notes), and (iv) Callon's 7.500% Senior Notes due 2030 (Callon's 2030 Notes, and together with the Callon Credit Agreement, Callon's 2026 Notes, and Callon's 2028 Notes, the Callon Indebtedness).

The Credit Agreement has limited conditions to funding on the Closing Date loans requested by APA in accordance with the Credit Agreement, such as consummation of the transactions under the Merger Agreement, no Company Material Adverse Effect (as defined in the Merger Agreement) has occurred, repayment of all indebtedness outstanding under the Callon Credit Agreement and Callon's 2026 Notes, and Callon having no other material indebtedness for borrowed money except for Callon's 2028 Notes and Callon's 2030 Notes or as permitted under the Credit Agreement or the Merger Agreement.

Proceeds of loans made under the Credit Agreement may only be used to refinance the Callon Indebtedness and repay fees and expenses related to transactions under the Credit Agreement and the Merger Agreement. To the extent that borrowings by APA under the Credit Agreement are not so used on or before the date that is 120 days after the Closing Date, APA then must prepay the amount of such unused borrowings.

Apache has guaranteed obligations under the Credit Agreement effective until the aggregate principal amount of indebtedness under senior notes and debentures outstanding under Apache's existing indentures first is less than $1.0 billion.

If $400 million or more in aggregate principal amount of Callon's 2028 Notes and Callon's 2030 Notes remains outstanding on the date which is 120 days after the Closing Date, Callon then must guarantee APA's obligations under the Credit Agreement effective until the aggregate outstanding principal amount of Callon's 2028 Notes and Callon's 2030 Notes first is less than $400 million.

APA may at any time prepay loans under the Credit Agreement. APA may at any time terminate, or from time to time reduce, the lenders' commitments under the Credit Agreement. Unless previously terminated, the lenders' commitments automatically terminate on the first to occur of: (i) the Closing Date, after giving effect to funding of each lender's commitments on the Closing Date, (ii) APA's acquisition of Callon pursuant to the Merger Agreement without loans being made under the Credit Agreement, (iii) termination of the Merger Agreement in accordance with its terms, and (iv) the Termination Date (as defined in, and may be extended pursuant to, the Merger Agreement).

All borrowings under the Credit Agreement would be in U.S. Dollars and bear interest at one of the following two rate options, as selected by APA, plus the indicated margin:

- One option is a base rate per annum equal to the greatest of (i) the applicable prime rate, (ii) the greater of the applicable federal funds rate and overnight bank funding rate, plus 0.50%, and (iii) an adjusted secured overnight financing rate published by the Federal Reserve Bank of New York (SOFR) for a one-month interest period plus 1.0%. The margin for this rate option (Term Base Rate Margin) is a rate per annum varying from 0.25% to 1.0% for 364-Day Tranche Loans, 0.375% to 1.125% for 3-Year Tranche Loans until the second anniversary of the Closing Date, and 0.625% to 1.375% for 3-Year Tranche Loans after the second anniversary of the Closing Date, in each case, based on the rating for senior, unsecured, non-credit enhanced, long-term indebtedness for borrowed money of APA, or if such indebtedness is not rated and the Apache guaranty is in effect, of Apache. Apache's Long-Term Debt Rating currently applies.

- The second option is an adjusted SOFR rate, plus a margin at a rate per annum varying from 1.25% to 2.0% for 364-Day Tranche Loans, 1.375% to 2.125% for 3-Year Tranche Loans until the second anniversary of the Closing Date, and 1.625% to 2.375% for 3-Year Tranche Loans after the second anniversary of the Closing Date, in each case, based on the Long-Term Debt Rating (Term Applicable Margin). For SOFR-based interest rates, APA may select an interest period of one, three, or six months.

Currently, the Term Base Rate Margin is 0.625% for 364-Day Tranche Loans and 0.75% for 3-Year Tranche Loans, and the Term Applicable Margin is 1.625% for 364-Day Tranche Loans and 1.75% for 3-Year Tranche Loans.

The Credit Agreement provides for a ticking fee payable by APA at a rate of 0.225% per annum on the daily average undrawn aggregate commitments thereunder; the ticking fee accrues during the period beginning on the date that is 90 days after January 3, 2024 to the earlier of (i) termination or expiration of the commitments or (ii) the Closing Date.

APA is subject to representations and warranties, covenants, and events of default under the Credit Agreement substantially similar to those in APA's existing 2022 Agreements. The Credit Agreement does not permit lenders to accelerate maturity based on unspecified material adverse changes and does not have prepayment obligations in the event of a decline in credit ratings.

10. INCOME TAXES

Net income before income taxes was composed of the following:

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
U.S.	$ 627	$ 2,675	$ 629
Foreign	2,256	3,059	1,262
Total	$ 2,883	$ 5,734	$ 1,891

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

	For the Year Ended December 31,		
	2023	**2022**	**2021**
		(In millions)	
Current income taxes:			
Federal	$ 2	$ 1	$ 16
State	6	11	—
Foreign	1,330	1,495	636
	1,338	1,507	652
Deferred income taxes:			
Federal	(1,708)	—	—
State	(32)	—	—
Foreign	78	145	(74)
	(1,662)	145	(74)
Total	$ (324)	$ 1,652	$ 578

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,		
	2023	**2022**	**2021**
		(In millions)	
Income tax expense at U.S. statutory rate	$ 605	$ 1,204	$ 397
State income tax, less federal effect(1)	(23)	9	—
Taxes related to foreign operations	752	745	298
Tax credits	—	(4)	(10)
Net change in tax contingencies	5	1	16
Valuation allowances(1)	(1,842)	(646)	(90)
Tax adjustments attributable to BCP Business Combination	—	126	—
Remeasurement of U.K. deferred tax liability	174	208	—
Tax attributable to Altus Preferred Unit limited partners	—	—	(34)
All other, net	5	9	1
	$ (324)	$ 1,652	$ 578

(1) The change in state valuation allowance is included as a component of state income tax.

The net deferred income tax (asset) liability 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) liability consisted of the following as of December 31:

	2023	2022
	(In millions)	
Deferred tax assets:		
U.S. and state net operating losses	$ 2,050	$ 2,029
Capital losses	8	357
Foreign net operating losses	43	27
Tax credits and other tax incentives	26	26
Foreign tax credits	2,204	2,241
Accrued expenses and liabilities	129	156
Asset retirement obligation	850	672
Property and equipment	38	44
Equity investments	8	—
Net interest expense limitation	125	74
Lease liability	71	114
Decommissioning contingency for sold Gulf of Mexico properties	210	275
Total deferred tax assets	5,762	6,015
Valuation allowance	(2,630)	(4,918)
Net deferred tax assets	3,132	1,097
Deferred tax liabilities:		
Equity investments	—	1
Property and equipment	1,573	1,023
Right-of-use asset	69	110
Decommissioning security for sold Gulf of Mexico properties	44	148
Other	59	90
Total deferred tax liabilities	1,745	1,372
Net deferred income tax (asset) liability	$ (1,387)	$ 275

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

	2023	2022
	(In millions)	
Assets:		
Other assets		
Deferred tax asset	$ 1,758	$ 39
Liabilities:		
Deferred credits and other noncurrent liabilities		
Deferred tax liability	371	314
Net deferred income tax (asset) liability	$ (1,387)	$ 275

On July 14, 2022, the Energy (Oil and Gas) Profits Levy Act of 2022 (the Energy Profits Levy) was enacted, receiving Royal Assent. Under the law, an additional levy was assessed at a 25 percent rate and is effective for the period of May 26, 2022, through December 31, 2025. The Finance Act 2023 included amendments to the Energy Profits Levy that increased the levy from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023 through March 31, 2028. Under U.S. GAAP, the financial statement impact of new legislation is recorded in the period of enactment. As a result, the Company recorded a deferred tax expense of $208 million and $174 million related to the remeasurement of the U.K. deferred tax liability in 2022 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 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 is not an applicable corporation in 2023 but will be subject to CAMT beginning on January 1, 2024. The Company is continuing to evaluate the provisions of the IRA and its effects on the Company's consolidated financial statements.

On January 14, 2022, Apache Midstream LLC, a wholly owned subsidiary of Apache, exchanged 12.5 million Common Units in Altus Midstream LP for 12.5 million shares of ALTM Class A Common Stock, in a taxable exchange. On February 22, 2022, as a result of the BCP Business Combination, the Company deconsolidated ALTM. On March 11, 2022, the Company sold four million of its Kinetik Shares. The Company recorded tax expense of $126 million associated with the BCP Business Combination. The tax impact of the BCP Business Combination was fully offset by a change in valuation allowance. Refer to Note 2— Acquisitions and Divestitures for further detail.

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. The Company showed positive income over the three-year period ended December 31, 2023. 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. The remaining U.S. valuation allowance relates primarily to foreign tax credit and capital loss carryforwards.

In 2023, 2022, and 2021, the Company's valuation allowance decreased by $2.3 billion, $1.0 billion, and $89 million, respectively, as detailed in the table below:

	2023	2022	2021
		(In millions)	
Balance at beginning of year	$ 4,918	$ 5,902	$ 5,991
State[1]	(63)	(111)	1
U.S.	(2,235)	(706)	(97)
Foreign	10	(167)	7
Balance at end of year	$ 2,630	$ 4,918	$ 5,902

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

On December 31, 2023, the Company had net operating losses as follows:

	Amount	Expiration
	(In millions)	
U.S.	$ 8,027	2027 - Indefinite
State	6,553	Various
Foreign	119	2024 - Indefinite

The Company has a U.S. net operating loss carryforward of $8.0 billion, which includes $107 million 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 $6.6 billion, foreign net operating losses of $119 million, and a net interest expense carryover of $580 million under Section 163(j) of the Code with indefinite carryover. In 2023, $1.7 billion of U.S. capital loss carryforward expired unutilized with $34 million remaining, which has a five year carryover period expiring in 2027. The Company has recorded a valuation allowance against some of the U.S. net operating losses, a majority of 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. and state net operating losses, and the net interest expense carryover will be utilized prior to their expiration.

On December 31, 2023, the Company had foreign tax credits as follows:

	Amount	Expiration
	(In millions)	
Foreign tax credits	$ 2,204	2025-2026

The Company has a $2.2 billion U.S. foreign tax credit carryforward. The Company has recorded a full 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 that 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:

	2023	2022	2021
		(In millions)	
Balance at beginning of year	$ 89	$ 116	$ 93
Additions based on tax positions related to prior year	4	—	16
Additions based on tax positions related to the current year	—	—	7
Reductions for tax positions of prior years	—	(27)	—
Balance at end of year	$ 93	$ 89	$ 116

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 each of the years ended December 31, 2023, 2022, and 2021, the Company recorded tax expense of $2 million, $1 million, and $1 million, respectively, for interest and penalties. At December 31, 2023, 2022, and 2021, the Company had an accrued liability for interest and penalties of $7 million, $5 million, and $4 million, respectively.

In 2023, 2022, and 2021, the Company recorded a $4 million net increase, a $27 million net decrease, and a $23 million net increase, respectively, in its reserve for uncertain tax positions.

On September 26, 2022, the Company received a Statutory Notice of Deficiency from the IRS disallowing certain net operating loss carryback and research and development credit refund claims. As a result of the disallowance, on December 14, 2022, the Company filed a petition with the U.S. Tax Court challenging the tax adjustments and requesting a redetermination of the deficiencies stated in the notice.

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	2005
U.K.	2022

11. 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, 2023, the Company has an accrued liability of approximately $83 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.

Argentine Environmental Claims

On March 12, 2014, the Company and its subsidiaries completed the sale of all of the Company's subsidiaries' operations and properties in Argentina to YPF Sociedad Anonima (YPF). As part of that sale, YPF assumed responsibility for all of the past, present, and future litigation in Argentina involving Company subsidiaries, except that Company subsidiaries have agreed to indemnify YPF for certain environmental, tax, and royalty obligations capped at an aggregate of $100 million. The indemnity is subject to specific agreed conditions precedent, thresholds, contingencies, limitations, claim deadlines, loss sharing, and other terms and conditions. On April 11, 2014, YPF provided its first notice of claims pursuant to the indemnity. Company subsidiaries have not paid any amounts under the indemnity but will continue to review and consider claims presented by YPF. Further, Company subsidiaries retain the right to enforce certain Argentina-related indemnification obligations against Pioneer Natural Resources Company (Pioneer) in an amount up to $45 million pursuant to the terms and conditions of stock purchase agreements entered in 2006 between Company subsidiaries and subsidiaries of Pioneer.

Louisiana Restoration

Louisiana surface owners often file lawsuits or assert claims against oil and gas companies, including the Company, claiming that operators and working interest owners in the chain of title are liable for environmental damages on the leased premises, including damages measured by the cost of restoration of the leased premises to its original condition, regardless of the value of the underlying property. From time to time, restoration lawsuits and claims are resolved by the Company for amounts that are not material to the Company, while new lawsuits and claims are asserted against the Company. With respect to each of the pending lawsuits and claims, the amount claimed is not currently determinable or is not material. Further, the overall exposure related to these lawsuits and claims is not currently determinable. While adverse judgments against the Company are possible, the Company intends to actively defend these lawsuits and claims.

Starting in November of 2013 and continuing into 2023, several parishes in Louisiana have pending lawsuits against many oil and gas producers, including the Company. In these cases, the Parishes, as plaintiffs, allege that defendants' oil and gas exploration, production, and transportation operations in specified fields were conducted in violation of the State and Local Coastal Resources Management Act of 1978, as amended, and applicable regulations, rules, orders, and ordinances promulgated or adopted thereunder by the Parish or the State of Louisiana. Plaintiffs allege that defendants caused substantial damage to land and water bodies located in the coastal zone of Louisiana. Plaintiffs seek, among other things, unspecified damages for alleged violations of applicable law within the coastal zone, the payment of costs necessary to clear, re-vegetate, detoxify, and otherwise restore the subject coastal zone as near as practicable to its original condition, and actual restoration of the coastal zone to its original condition. Without acknowledging or admitting any liability and solely to avoid the expense and uncertainty of future litigation, the Company agreed to settle with the State of Louisiana and Louisiana coastal Parishes to resolve any potential liability on the part of the Company for claims that were or could have been asserted by the coastal Parishes and/or the State of Louisiana in the pending litigation. The settlement is subject to court approval, which the parties hope to receive at some point in the first half of 2024. The consideration to be provided by the Company in the settlement will not have a material impact on the Company's financial position. Following settlement of these various lawsuits, the Company will be a defendant in only one remaining coastal zone lawsuit, which has been filed by the City of New Orleans against a number of oil and gas operators.

Apollo Exploration Lawsuit

In a case captioned *Apollo Exploration, LLC, Cogent Exploration, Ltd. Co. & SellmoCo, LLC v. Apache Corporation*, Cause No. CV50538 in the 385th Judicial District Court, Midland County, Texas, plaintiffs alleged damages in excess of $200 million (having previously claimed in excess of $1.1 billion) relating to purchase and sale agreements, mineral leases, and area of mutual interest agreements concerning properties located in Hartley, Moore, Potter, and Oldham Counties, Texas. The trial court entered final judgment in favor of the Company, ruling that the plaintiffs take nothing by their claims and awarding the Company its attorneys' fees and costs incurred in defending the lawsuit. The court of appeals affirmed in part and reversed in part the trial court's judgment thereby reinstating some of plaintiffs' claims. The Texas Supreme Court granted the Company's petition for review and heard oral argument in October 2022. On April 28, 2023, the Texas Supreme Court reversed the court of appeals' decision and remanded the case back to the court of appeals for further proceedings. After plaintiffs' request for rehearing, on July 21, 2023, the Texas Supreme Court reaffirmed its reversal of the court of appeals' decision and remand of the case back to the court of appeals for further proceedings.

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. The Company will vigorously prosecute its claim while vigorously defending against Quadrant's counter claims.

Canadian Operations Divestiture Dispute

Pursuant to a Sale and Purchase Agreement dated July 6, 2017 (Paramount SPA), the Company and its subsidiaries divested their remaining Canadian operations to Paramount Resources LTD (Paramount). Closing occurred on August 16, 2017. On September 11, 2019, four ex-employees of Apache Canada LTD on behalf of themselves and individuals employed by Apache Canada LTD on July 6, 2017, filed an Amended Statement of Claim in a matter styled *Stephen Flesch et. al. v Apache Corporation et. al.*, No. 1901-09160 Court of Queen's Bench of Alberta against the Company and others seeking class certification and a finding that the Paramount SPA amounted to a Change of Control of the Company, entitling them to accelerated vesting under the Company's equity plans. In the suit, the class seeks approximately $60 million USD and punitive damages. Without acknowledging or admitting any liability and solely to avoid the expense and uncertainty of future litigation, Apache has agreed to a settlement in the *Flesch* class action matter under which Apache will pay $7 million USD to resolve all claims against the Company asserted by the class. The settlement was approved by the court on October 26, 2023.

California and Delaware Litigation

On July 17, 2017, in three separate actions, San Mateo and Marin Counties, and the City of Imperial Beach, California, all filed suit individually and on behalf of the people of the state of California against over 30 oil and gas companies alleging damages as a result of global warming. Plaintiffs seek unspecified damages and abatement under various tort theories. On December 20, 2017, in two separate actions, the City of Santa Cruz and Santa Cruz County filed similar lawsuits against many of the same defendants. On January 22, 2018, the City of Richmond filed a similar lawsuit.

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 intends to challenge personal jurisdiction in California and to vigorously defend the Delaware lawsuit.

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 has not been certified and seeks to represent a group of owners allegedly owed statutory interest under New Mexico law as a result of purported late oil and gas payments. The amount of this claim is not yet reasonably determinable. The Company intends to vigorously defend against the claims asserted in this lawsuit.

Shareholder and Derivative Lawsuits

On February 23, 2021, a case captioned *Plymouth County Retirement System v. Apache Corporation, et al.* was filed in the United States District Court for the Southern District of Texas (Houston Division) against the Company and certain current and former officers. The complaint, which is a shareholder lawsuit styled as a class action, alleges that (1) the Company intentionally used unrealistic assumptions regarding the amount and composition of available oil and gas in Alpine High; (2) the Company did not have the proper infrastructure in place to safely and/or economically drill and/or transport those resources even if they existed in the amounts purported; (3) certain statements and omissions artificially inflated the value of the Company's operations in the Permian Basin; and (4) as a result, the Company's public statements were materially false and misleading. The Company intends to vigorously defend this lawsuit.

On February 21, 2023, a case captioned *Steve Silverman, Derivatively and on behalf of Nominal Defendant APA Corp. v. John J. Christmann IV, et al.* was filed in federal district court for the Southern District of Texas. Then, on July 21, 2023, a case captioned *Yang-Li-Yu, Derivatively and on behalf of Nominal Defendant APA Corp. v. John J. Christmann IV, et al.* was filed in federal district court for the Southern District of Texas. These cases have now been consolidated as *In Re APA Corporation Derivative Litigation*, Case No. 4:23-cv-00636 in the Southern District of Texas and purport to be derivative actions brought against senior management and Company directors over many of the same allegations included in the *Plymouth County Retirement System* matter and asserts claims of (1) breach of fiduciary duty; (2) waste of corporate assets; and (3) unjust enrichment. The defendants intend to vigorously defend these lawsuits.

Environmental Matters

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state, local, and foreign country 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 and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company manages its exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. The Company also conducts periodic reviews, on a Company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, the amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, the Company may exclude a property from the acquisition, require the seller to remediate the property to the Company's satisfaction, or agree to assume liability for the remediation of the property. The Company's general policy is to limit any reserve additions to any incidents or sites that are considered probable to result in an expected remediation cost exceeding $300,000. Any environmental costs and liabilities that are not reserved for are treated as an expense when actually incurred. In the Company's estimation, neither these expenses nor expenses related to training and compliance programs are likely to have a material impact on its financial condition.

As of December 31, 2023, the Company had an undiscounted reserve for environmental remediation of approximately $5 million.

On September 11, 2020, the Company received a Notice of Violation and Finding of Violation, and accompanying Clean Air Act Information Request, from the U.S. Environmental Protection Agency (EPA) following site inspections in April 2019 at several of the Company's oil and natural gas production facilities in Lea and Eddy Counties, New Mexico. Then on December 29, 2020, the Company received a Notice of Violation and Opportunity to Confer, and accompanying Clean Air Act Information Request, from the EPA following helicopter flyovers in September 2019 of several of the Company's oil and natural gas production facilities in Reeves County, Texas. The notices and information requests involved alleged emissions control and reporting violations. The Company cooperated with the EPA, responded to the information requests, and negotiated and entered into a consent decree to resolve the alleged violations in both New Mexico and Texas, which will be subject to court approval. The consideration to be provided by the Company in connection with the consent decree will not have a material impact on the Company's financial position.

The Company is not aware of any environmental claims existing as of December 31, 2023, 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 Mexico (GOM) Shelf operations and properties and its GOM operating subsidiary, GOM Shelf LLC (GOM Shelf) to Fieldwood Energy LLC (Fieldwood). Under the terms of the purchase agreement, Apache received cash consideration of $3.75 billion and 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 GOM Assets). In respect of such abandonment obligations, Fieldwood posted letters of credit in favor of Apache (Letters of Credit) and established trust accounts (Trust A and Trust B) of which Apache was a beneficiary and which were funded by two net profits interests (NPIs) depending on future oil prices. On February 14, 2018, Fieldwood filed for protection under Chapter 11 of the U.S. Bankruptcy Code. In connection with the 2018 bankruptcy, Fieldwood confirmed a plan under which Apache agreed, inter alia, to (i) accept bonds in exchange for certain of the Letters of Credit and (ii) amend the Trust A trust agreement and one of the NPIs to consolidate the trusts into a single Trust (Trust A) funded by both remaining NPIs. Following the 2018 reorganization of Fieldwood, Apache held two bonds (Bonds) and five Letters of Credit securing Fieldwood's asset retirement obligations on the Legacy GOM Assets as and when Apache is required to perform or pay for decommissioning any Legacy GOM Asset over the remaining life of the Legacy GOM Assets.

On August 3, 2020, Fieldwood again filed for protection under Chapter 11 of the U.S. Bankruptcy Code. On June 25, 2021, the United States Bankruptcy Court for the Southern District of Texas (Houston Division) entered an order confirming Fieldwood's bankruptcy plan. On August 27, 2021, Fieldwood's bankruptcy plan became effective. Pursuant to the plan, the Legacy GOM 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 GOM Assets will be used to fund the operation of GOM Shelf and the decommissioning of Legacy GOM Assets.

By letter dated April 5, 2022, replacing two prior letters dated September 8, 2021 and February 22, 2022, 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 is currently obligated to perform on certain of the Legacy GOM Assets. As a result, Apache and other current and former owners in these assets have received orders from BSEE to decommission certain of the Legacy GOM Assets included in GOM Shelf's notifications to BSEE. Apache expects to receive similar orders on the other Legacy GOM Assets included in GOM Shelf's notification letters. Apache has also received orders to decommission other Legacy GOM 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 GOM Assets.

As of December 31, 2023, Apache has incurred $819 million in decommissioning costs related to Legacy GOM Assets. GOM Shelf did not, and has confirmed that it will not, reimburse Apache for these decommissioning costs. As a result, Apache has sought and will continue to seek reimbursement from its security for these costs. As of December 31, 2023, $293 million has been reimbursed from Trust A and $336 million has been reimbursed from the Letters of Credit. If GOM Shelf does not reimburse Apache for further decommissioning costs incurred with respect to Legacy GOM Assets, then Apache will continue to seek reimbursement from Trust A, to the extent of available funds, and thereafter, will seek reimbursement from the Bonds and the Letters of Credit until all such funds and securities are fully utilized. In addition, after such sources have been exhausted, Apache has agreed to provide a standby loan to GOM Shelf of up to $400 million to perform decommissioning (Standby Loan Agreement), with such standby loan secured by a first and prior lien on the Legacy GOM Assets.

If the combination of GOM Shelf's net cash flow from its producing properties, the Trust A funds, the Bonds, and the remaining Letters of Credit are insufficient to fully fund decommissioning of any Legacy GOM Assets that Apache may be required to perform or fund, or if GOM Shelf's net cash flow from its remaining producing properties after the Trust A funds, Bonds, and Letters of Credit are exhausted is insufficient to repay any loans made by Apache under the Standby Loan Agreement, then Apache may be forced to use its available cash to fund the deficit.

As of December 31, 2023, Apache estimates that its potential liability to fund the remaining decommissioning of Legacy GOM Assets it may be ordered to perform or fund ranges from $824 million 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 has recorded a contingent liability of $824 million as of December 31, 2023, representing the estimated costs of decommissioning it may be required to perform or fund on Legacy GOM Assets. Of the total liability recorded, $764 million is reflected under the caption "Decommissioning contingency for sold Gulf of Mexico properties," and $60 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 decommissioning rig spread rates, lift boat rates, and planned abandonment logistics could result in a liability in excess of the amount accrued.

As of December 31, 2023, the Company has also recorded a $199 million asset, which represents the remaining amount the Company expects to be reimbursed from the Trust A funds, the Bonds, and the Letters of Credit for decommissioning it may be required to perform on Legacy GOM Assets. Of the total asset recorded, $21 million is reflected under the caption "Decommissioning security for sold Gulf of Mexico properties," and $178 million is reflected under "Other current assets."

The Company recognized $212 million, $157 million, and $446 million during 2023, 2022, and 2021, respectively, of "Losses on previously sold Gulf of Mexico properties" to reflect the net impact of changes to the estimated decommissioning liability and decommissioning asset to the Company's statement of consolidated operations.

On June 21, 2023, the two sureties that issued bonds directly to Apache and two sureties that issued bonds to the issuing bank on the Letters of Credit filed suit against Apache in a case styled *Zurich American Insurance Company, HCC International Insurance Company PLC, Philadelphia Indemnity Insurance Company and Everest Reinsurance Company (Insurers) v. Apache Corporation*, Cause No. 2023-38238 in the 281st Judicial District Court, Harris County Texas. Insurers are seeking to prevent Apache from drawing on the Bonds and Letters of Credit and further allege that they are discharged from their reimbursement obligations related to decommissioning costs and are entitled to other relief. On July 20, 2023, the 281st Judicial District Court denied the Insurers' request for a temporary injunction. On July 26, 2023, Apache removed the suit to the United States Bankruptcy Court for the Southern District of Texas (Houston Division) which subsequently held that the sureties' state court lawsuit violated the terms of the Bankruptcy Confirmation Order and is void. Apache has drawn down the entirety of the Letters of Credit and is vigorously pursuing its claims against the sureties.

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 an 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 $168 million, $145 million, and $128 million for the years ended 2023, 2022, and 2021, 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 $71 million, $62 million, and $20 million in 2023, 2022, and 2021, respectively. In 2023 these costs primarily related to decommissioning work in the Gulf of Mexico. In 2022 and 2021, these costs were primarily related to drilling activities in Block 58 offshore Suriname.

Finance lease assets are included in "Property, Plant, 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 2023, 2022, and 2021. Interest on the Company's finance lease liability was $1 million, $2 million, and $2 million in 2023, 2022, and 2021, respectively.

The following table represents the Company's weighted average lease term and discount rate as of December 31, 2023:

	Operating Leases	Finance Lease
Weighted average remaining lease term	6.9 years	9.7 years
Weighted average discount rate	5.3 %	4.4 %

At December 31, 2023, 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][5]
		(In millions)	
2024	$ 116	$ 3	$ 250
2025	35	3	197
2026	21	4	766
2027	23	4	143
2028	22	4	141
Thereafter	129	23	208
Total future minimum payments	346	41	$ 1,705
Less: imputed interest	(65)	(9)	N/A
Total lease liabilities	281	32	N/A
Current portion	116	2	N/A
Non-current portion	$ 165	$ 30	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 $182 million, $183 million, and $198 million in 2023, 2022, and 2021, respectively.

(5) Under terms agreed to in the Egypt merged concession agreement entered into in 2021, the Company committed to spend a minimum of $3.5 billion on exploration, development, and operating activities by March 31, 2026. As of December 31, 2023, the Company has spent $2.9 billion and believes it will be able to satisfy the remaining obligation within its current exploration and development program.

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 $74 million, $90 million, and $64 million in 2023, 2022, and 2021, respectively.

12. 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, $40 million, and $31 million for 2023, 2022, and 2021, 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, 2023, 2022, and 2021, 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.

	2023		2022		2021	
	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	$ 108	$ 15	$ 211	$ 20	$ 233	$ 20
Service cost	1	1	2	1	3	1
Interest cost	5	1	3	—	3	—
Foreign currency exchange rates	6	—	(21)	—	(2)	—
Actuarial losses (gains)	3	—	(79)	(5)	(5)	1
Plan settlements	—	—	—	—	(17)	—
Benefits paid	(5)	(3)	(8)	(3)	(4)	(4)
Retiree contributions	—	1	—	2	—	2
Projected benefit obligation at end of year	118	15	108	15	211	20
Change in Plan Assets						
Fair value of plan assets at beginning of year	137	—	254	—	262	—
Actual return (loss) on plan assets	8	—	(87)	—	11	—
Foreign currency exchange rates	8	—	(26)	—	(3)	—
Employer contributions	2	1	4	2	5	2
Plan settlements	—	—	—	—	(17)	—
Benefits paid	(5)	(3)	(8)	(4)	(4)	(4)
Retiree contributions	—	2	—	2	—	2
Fair value of plan assets at end of year	150	—	137	—	254	—
Funded status at end of year	$ 32	$ (15)	$ 29	$ (15)	$ 43	$ (20)
Amounts recognized in Consolidated Balance Sheet						
Current liability	$ —	$ (2)	$ —	$ (2)	$ —	$ (2)
Non-current asset (liability)	32	(13)	29	(13)	43	(18)
	$ 32	$ (15)	$ 29	$ (15)	$ 43	$ (20)
Pre-tax Amounts Recognized in Accumulated Other Comprehensive Income (Loss)						
Accumulated gain (loss)	$ (12)	$ 16	$ (10)	$ 18	$ 1	$ 14
Weighted Average Assumptions used as of December 31						
Discount rate	4.80 %	5.00 %	5.00 %	5.29 %	1.80 %	2.57 %
Salary increases	4.60 %	N/A	4.70 %	N/A	4.90 %	N/A
Expected return on assets	4.80 %	N/A	4.70 %	N/A	1.90 %	N/A
Healthcare cost trend						
Initial	N/A	6.25 %	N/A	6.50 %	N/A	6.25 %
Ultimate in 2030	N/A	5.25 %	N/A	5.25 %	N/A	5.00 %

As of December 31, 2023, 2022, and 2021, the accumulated benefit obligation for the U.K. Pension Plan was $112 million, $89 million, and $205 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	
	2023	**2022**
Asset Category		
Global equities	— %	6 %
Multi-asset credit	59 %	40 %
Nominal bonds	6 %	24 %
Inflation-linked bonds	33 %	28 %
Cash	2 %	2 %
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, 2023 and 2022 are based upon unadjusted quoted prices for identical instruments in active markets, which is a Level 1 fair value measurement. The following tables present the fair values of plan assets for each major asset category based on the nature and significant concentration of risks in plan assets at December 31, 2023 and 2022:

	December 31,	
	2023	**2022**
	(In millions)	
Asset Category		
Global equities	$ —	$ 9
Multi-asset credit	88	55
Nominal bonds	9	32
Inflation-linked bonds	50	39
Cash	3	2
Total	$ 150	$ 137

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 3.5 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, 2023, 2022, and 2021:

	2023		2022		2021	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
			(In millions)			
Components of Net Periodic Benefit Cost						
Service cost	$ 1	$ 1	$ 2	$ 1	$ 3	$ 1
Interest cost	5	1	3	—	3	—
Expected return on assets	(7)	—	(4)	—	(4)	—
Amortization of loss	—	(2)	—	(1)	—	(1)
Settlement loss	—	—	—	—	—	—
Net periodic benefit cost	$ (1)	$ —	$ 1	$ —	$ 2	$ —
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost for the Years Ended December 31						
Discount rate	5.00 %	5.29 %	1.80 %	2.57 %	1.40 %	2.06 %
Salary increases	4.70 %	N/A	4.90 %	N/A	4.50 %	N/A
Expected return on assets	4.70 %	N/A	1.90 %	N/A	1.50 %	N/A
Healthcare cost trend						
Initial	N/A	6.50 %	N/A	6.25 %	N/A	6.00 %
Ultimate in 2030	N/A	5.25 %	N/A	5.00 %	N/A	5.00 %

The Company expects to contribute approximately $2 million to its pension plan and $2 million to its postretirement benefit plan in 2024. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Postretirement Benefits
	(In millions)	
2024	$ 5	$ 2
2025	5	2
2026	5	1
2027	6	1
2028	6	1
Years 2029-2033	34	6

13. REDEEMABLE NONCONTROLLING INTEREST — ALTUS

Preferred Units Issuance

On June 12, 2019, Altus Midstream LP issued and sold Preferred Units for an aggregate issue price of $625 million in a private offering exempt from the registration requirements of the Securities Act. Altus Midstream LP received approximately $611 million in cash proceeds from the sale after deducting transaction costs and discounts to certain purchasers.

Classification

Prior to the deconsolidation of Altus on February 22, 2022, at December 31, 2021, the carrying amount of the Preferred Units was recorded as “Redeemable Noncontrolling Interest — Altus Preferred Unit Limited Partners” and classified as temporary equity on the Company’s consolidated balance sheet based on the terms of the Preferred Units, including the redemption rights with respect thereto.

Measurement

Altus applied a two-step approach to subsequent measurement of the redeemable noncontrolling interest related to the Preferred Units by first allocating a portion of the net income of Altus Midstream LP in accordance with the terms of the partnership agreement. An additional adjustment to the carrying value of the Preferred Unit redeemable noncontrolling interest at each period end was recorded, if applicable. The amount of such adjustment was determined based upon the accreted value method to reflect the passage of time until the Preferred Units were exchangeable at the option of the holder. Accordingly, prior to the deconsolidation of Altus on February 22, 2022, the Company recorded a net loss attributable to Altus Preferred Unit limited partners totaling $70 million and net income attributable to Altus Preferred Unit limited partners totaling $162 million during 2022 and 2021, respectively.

14. CAPITAL STOCK

Common Stock Outstanding

The following table provides changes to the Company’s common shares outstanding for the years ended December 31, 2023, 2022, and 2021:

	For the Year Ended December 31,		
	2023	**2022**	**2021**
Balance, beginning of year	311,559,149	346,930,765	377,482,630
Shares issued for stock-based compensation plans:			
Treasury shares issued	2,016	1,996	3,133
Common shares issued	725,914	791,381	649,231
Treasury shares acquired	(8,711,178)	(36,164,993)	(31,204,229)
Balance, end of year	303,575,901	311,559,149	346,930,765

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, 2023, 2022, and 2021:

	2023			2022			2021		
	Income	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**	**Income**	**Shares**	**Per Share**
	(In millions, except per share amounts)								
Basic:									
Income attributable to common stock	$ 2,855	308	$ 9.26	$ 3,674	332	$ 11.05	$ 973	374	$ 2.60
Effect of Dilutive Securities:									
Stock compensation awards	$ —	1	$ (0.01)	$ —	1	$ (0.03)	$ —	1	$ (0.01)
Diluted:									
Income attributable to common stock	$ 2,855	309	$ 9.25	$ 3,674	333	$ 11.02	$ 973	375	$ 2.59

The diluted EPS calculation excludes options and restricted shares that were anti-dilutive totaling 1.9 million, 2.4 million, and 3.3 million for the years ended December 31, 2023, 2022, and 2021, respectively.

Stock Repurchase Program

During 2018, the Company’s Board of Directors authorized the purchase of up to 40 million shares of the Company’s common stock. During the fourth quarter of 2021, the Company’s Board of Directors authorized the purchase of an additional 40 million shares of the Company’s common stock. During the third quarter of 2022, the Company's Board of Directors further authorized the purchase of an additional 40 million shares of the Company's common stock.

During 2023, the Company repurchased 8.7 million shares at an average price of $37.81 per share, and as of December 31, 2023, the Company had remaining authorization to repurchase 43.9 million shares. During 2022, the Company repurchased 36.2 million shares at an average price of $39.34 per share. During 2021, the Company repurchased 31.2 million shares at an average price of $27.14 per share.

Subsequent to year-end 2023 and through the date of this filing on February 22, 2024, the Company repurchased 3.0 million shares at an average price of $33.27 per share. As of February 22, 2024, the Company had remaining authorization to repurchase up to 40.9 million shares.

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

The Company’s Board of Directors approved an increase in APA’s quarterly dividend from $0.025 per share to $0.0625 per share in the third quarter of 2021 and approved a further increase to $0.125 per share in the fourth quarter of 2021. During the third quarter of 2022, the Company’s Board of Directors approved another increase to its quarterly dividend to $0.25 per share, representing a return to pre-Covid-19 dividend levels. For the years ended December 31, 2023, 2022, and 2021, the Company declared common stock dividends totaling $1.00 per share, $0.75 per share, and $0.2375 per share, respectively.

Stock Compensation Plans

The Company maintains several stock-based compensation plans, which include stock options, restricted stock, and conditional restricted stock unit plans. In 2021, pursuant to the Holding Company Reorganization, Apache’s outstanding common shares were converted into equivalent corresponding shares of APA. APA assumed sponsorship of all stock compensation plans. All cash-settled awards previously indexed to Apache’s stock price were subsequently indexed to APA’s stock price, and all unvested stock-settled awards will be settled in APA stock upon vesting.

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, 2023, 9.4 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, 2023, 2022, and 2021:

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Stock-settled and cash-settled compensation expensed:			
Lease operating expenses	$ 27	$ 82	$ 39
Exploration	7	29	10
General and administrative	50	193	108
Total stock-settled and cash-settled compensation expensed	84	304	157
Stock-settled and cash-settled compensation capitalized	13	44	18
Total stock-settled and cash-settled compensation costs	$ 97	$ 348	$ 175

Stock Options

As of December 31, 2023, 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.

The following table summarizes stock option activity for the years ended December 31, 2023, 2022, and 2021:

	2023		2022		2021	
	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	2,078	$ 57.71	3,012	$ 63.79	3,537	$ 72.10
Exercised	(12)	42.38	(99)	42.09	—	—
Forfeited	—	—	(2)	49.10	—	—
Expired	(601)	80.53	(833)	81.56	(525)	119.83
Outstanding, end of year(1)	1,465	48.48	2,078	57.71	3,012	63.79
Expected to vest	—	—	—	—	—	—
Exercisable, end of year(1)	1,465	48.48	2,078	57.71	3,012	63.79

(1) As of December 31, 2023, options exercisable and outstanding had a weighted average remaining contractual life of 3.1 years and aggregate intrinsic value of $33,000.

During the years ended December 31, 2023, 2022, and 2021, there were no options issued and 12,183, 98,646, and no options, respectively, exercised.

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 either the Company's common stock or, prior to the BCP Business Combination, in ALTM's common stock, as applicable, 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, 2023, 2022, and 2021, compensation costs charged to expense for the restricted stock units and restricted stock phantom units was $73 million, $153 million, and $95 million, respectively. As of December 31, 2023, 2022, and 2021, capitalized compensation costs for the restricted stock units and restricted stock phantom units were $11 million, $22 million, and $15 million, respectively.

The following table summarizes stock-settled restricted stock unit activity for the years ended December 31, 2023, 2022, and 2021:

	2023		2022		2021	
	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	1,885	$ 23.08	2,073	$ 19.98	1,552	$ 28.43
Granted	661	41.60	847	29.90	1,506	16.46
Vested[3]	(975)	23.31	(978)	22.39	(857)	29.13
Forfeited	(69)	32.44	(57)	23.49	(128)	19.78
Expired	(22)	27.81	—	—	—	—
Non-vested, end of year[1][2]	1,480	30.69	1,885	23.08	2,073	19.98

(1) As of December 31, 2023, there was $15 million of total unrecognized compensation cost related to 1,479,880 unvested stock-settled restricted stock units.

(2) As of December 31, 2023, the weighted-average remaining life of unvested stock-settled restricted stock units is approximately 0.6 years.

(3) The grant date fair values of the stock-settled awards vested during 2023, 2022, and 2021 were approximately $23 million, $22 million, and $25 million, respectively.

The following table summarizes cash-settled restricted stock phantom unit activity for the years ended December 31, 2023, 2022, and 2021:

	For the Year Ended December 31,		
	2023	2022	2021
	(In thousands)		
Non-vested, beginning of year	5,709	6,402	4,423
Adjustment from ALTM transaction[1]	—	143	—
Granted[2]	1,972	2,568	4,441
Vested	(2,851)	(2,970)	(2,049)
Forfeited	(340)	(434)	(413)
Expired	(12)	—	—
Non-vested, end of year[3]	4,478	5,709	6,402

(1) Following the BCP Business Combination, certain employees were granted restricted stock phantom units based on APA's common stock price to replace the equivalent value in restricted stock phantom units based on ALTM's common stock price.

(2) Restricted stock phantom units granted during 2023, 2022, and 2021 included 1,972,116, 2,512,602, and 4,375,546 awards, respectively, based on the per-share market price of APA common stock. Restricted stock phantom units granted during 2022 and 2021 included 55,546 and 65,327 awards, respectively, based on the per-share market price of ALTM common stock prior to the deconsolidation of Altus on February 22, 2022.

(3) The outstanding liability for the unvested cash-settled restricted stock phantom units that had not been recognized as of December 31, 2023 was approximately $54 million.

In January 2024, the Company awarded 819,836 restricted stock units and 2,356,255 restricted stock phantom units based on APA's weighted-average per-share market price of $33.73 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 $28 million and $80 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, 2023, are as described below:

- In January 2020, the Company's Board of Directors approved the 2020 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial cash-settled conditional phantom units totaling 1,687,307 units. A total of 999,896 phantom units were outstanding as of December 31, 2023. The results for the performance period yielded a payout of 155 percent of target.
- In January 2021, the Company's Board of Directors approved the 2021 Performance Program, pursuant to the 2016 Plan. Eligible employees received the initial cash-settled conditional phantom units totaling 1,959,856 units. A total of 1,803,083 phantom units were outstanding as of December 31, 2023. The results for the performance period yielded a payout of 118 percent of target.
- 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. The actual number of phantom units awarded will be between zero and 200 percent of target. A total of 1,040,100 phantom units were outstanding as of December 31, 2023, from which a minimum of zero to a maximum of 2,080,200 units could be awarded.
- 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 784,977 phantom units were outstanding as of December 31, 2023, from which a minimum of zero to a maximum of 1,569,954 units could be awarded.

Compensation expense related to the conditional cash-settled awards is 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 $2 million, $143 million, and $57 million during 2023, 2022, and 2021, respectively. Capitalized compensation costs under the cash-settled performance programs were expenses of approximately $100 thousand, $21 million, and $3 million during 2023, 2022, and 2021, respectively.

The following table summarizes cash-settled conditional restricted stock phantom unit activity for the years ended December 31, 2023, 2022, and 2021:

	For the Year Ended December 31,		
	2023	**2022**	**2021**
		(In thousands)	
Non-vested, beginning of year	4,835	4,531	3,417
Granted	1,536	1,676	1,782
Vested	(1,593)	(656)	(76)
Forfeited	(99)	(106)	(240)
Expired	(50)	(610)	(352)
Non-vested, end of year[1]	4,629	4,835	4,531

(1) As of December 31, 2023, the outstanding liability for the unvested cash-settled conditional restricted stock phantom units that had not been recognized was approximately $24 million.

In January 2024, the Company's Board of Directors approved the 2024 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 2024 Performance Program. Eligible employees received conditional phantom units and cash incentives. The conditional phantom units totaled 644,399 units, with the ultimate units to be awarded ranging from zero to a maximum of 1,288,798 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.

15. ACCUMULATED OTHER COMPREHENSIVE INCOME

Components of accumulated other comprehensive income include the following:

	As of December 31,		
	2023	2022	2021
		(In millions)	
Pension and postretirement benefit plan (Note 12)	$ 15	$ 14	$ 22
Accumulated other comprehensive income	$ 15	$ 14	$ 22

16. 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 each of 2023 and 2022, sales to EGPC accounted for approximately 15 percent of the Company's worldwide crude oil, natural gas, and NGLs revenues. During 2021, sales to EGPC and CFE International accounted for approximately 14 percent and 10 percent, respectively, of the Company's worldwide crude oil, natural gas, and NGLs revenues.

Management does not believe that the loss of any one of these customers would have a material adverse effect on the results of operations.

17. BUSINESS SEGMENT INFORMATION

As of December 31, 2023, the Company's consolidated subsidiaries are engaged in exploration and production (Upstream) activities across three operating segments: Egypt, North Sea, and the U.S. The Company's Upstream business explores for, develops, and produces crude oil, natural gas, and natural gas liquids. Prior to the deconsolidation of Altus on February 22, 2022, the Company's Midstream business was operated by ALTM, which owned, developed, and operated a midstream energy asset network in the Permian Basin of West Texas. The Company also has active exploration and appraisal operations ongoing in Suriname, as well as interests in Uruguay and other international locations that may, over time, result in reportable discoveries and development opportunities. Financial information for each segment is presented below:

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
			(In millions)			
2023						
Oil revenues	$ 2,683	$ 1,073	$ 2,241	$ —	$ —	$ 5,997
Natural gas revenues	346	237	297	—	—	880
Natural gas liquids revenues	—	28	480	—	—	508
Oil, natural gas, and natural gas liquids production revenues	3,029	1,338	3,018	—	—	7,385
Purchased oil and gas sales	—	—	894	—	—	894
	3,029	1,338	3,912	—	—	8,279
Operating Expenses:						
Lease operating expenses	474	369	593	—	—	1,436
Gathering, processing, and transmission	33	52	249	—	—	334
Purchased oil and gas costs	—	—	742	—	—	742
Taxes other than income	—	—	207	—	—	207
Exploration[4]	119	19	14	—	43	195
Depreciation, depletion, and amortization	524	271	745	—	—	1,540
Asset retirement obligation accretion	—	76	40	—	—	116
Impairments	—	50	11	—	—	61
	1,150	837	2,601	—	43	4,631
Operating Income (Loss)	$ 1,879	$ 501	$ 1,311	$ —	$ (43)	3,648
Other Income (Expense):						
Gain on divestitures, net						8
Losses on previously sold Gulf of Mexico properties						(212)
Derivative instrument gains, net						99
Other						18
General and administrative						(351)
Transaction, reorganization, and separation						(15)
Financing costs, net						(312)
Income Before Income Taxes						$ 2,883
Total Assets[3]	$ 3,503	$ 1,970	$ 9,221	$ —	$ 550	$ 15,244
Net Property and Equipment	$ 2,209	$ 1,628	$ 5,689	$ —	$ 512	$ 10,038
Additions to Net Property and Equipment	$ 834	$ 131	$ 1,255	$ —	$ 93	$ 2,313

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
	(In millions)					
2022						
Oil revenues	$ 3,145	$ 1,232	$ 2,458	$ —	$ —	$ 6,835
Natural gas revenues	370	281	918	—	—	1,569
Natural gas liquids revenues	6	45	768	—	(3)	816
Oil, natural gas, and natural gas liquids production revenues	3,521	1,558	4,144	—	(3)	9,220
Purchased oil and gas sales	—	—	1,850	5	—	1,855
Midstream service affiliate revenues	—	—	—	16	(16)	—
	3,521	1,558	5,994	21	(19)	11,075
Operating Expenses:						
Lease operating expenses	526	404	515	—	(1)	1,444
Gathering, processing, and transmission	22	43	315	5	(18)	367
Purchased oil and gas costs	—	—	1,776	—	—	1,776
Taxes other than income	—	—	265	3	—	268
Exploration[4]	84	35	24	—	162	305
Depreciation, depletion, and amortization	400	238	593	2	—	1,233
Asset retirement obligation accretion	—	82	34	1	—	117
	1,032	802	3,522	11	143	5,510
Operating Income (Loss)	$ 2,489	$ 756	$ 2,472	$ 10	$ (162)	5,565
Other Income (Expense):						
Gain on divestitures, net						1,180
Losses on previously sold Gulf of Mexico properties						(157)
Derivative instrument losses, net						(114)
Other						148
General and administrative						(483)
Transaction, reorganization, and separation						(26)
Financing costs, net						(379)
Income Before Income Taxes						$ 5,734
Total Assets[3]	$ 3,148	$ 1,911	$ 7,574	$ —	$ 514	$ 13,147
Net Property and Equipment	$ 1,976	$ 1,386	$ 5,226	$ —	$ 424	$ 9,012
Additions to Net Property and Equipment	$ 695	$ 210	$ 1,439	$ —	$ 263	$ 2,607

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
	(In millions)					
2021						
Oil revenues	$ 1,806	$ 929	$ 1,850	$ —	$ —	$ 4,585
Natural gas revenues	270	183	754	—	—	1,207
Natural gas liquids revenues	9	24	676	—	(3)	706
Oil, natural gas, and natural gas liquids production revenues	2,085	1,136	3,280	—	(3)	6,498
Purchased oil and gas sales	—	—	1,476	11	—	1,487
Midstream service affiliate revenues	—	—	—	127	(127)	—
	2,085	1,136	4,756	138	(130)	7,985
Operating Expenses:						
Lease operating expenses	469	383	391	—	(2)	1,241
Gathering, processing, and transmission	12	39	309	32	(128)	264
Purchased oil and gas costs	—	—	1,575	5	—	1,580
Taxes other than income	—	—	190	14	—	204
Exploration[4]	63	34	28	—	30	155
Depreciation, depletion, and amortization	524	270	554	12	—	1,360
Asset retirement obligation accretion	—	79	30	4	—	113
Impairments	26	22	—	160	—	208
	1,094	827	3,077	227	(100)	5,125
Operating Income (Loss)	$ 991	$ 309	$ 1,679	$ (89)	$ (30)	2,860
Other Income (Expense):						
Gain on divestitures, net						67
Losses on previously sold Gulf of Mexico properties						(446)
Derivative instrument gains, net						94
Other						228
General and administrative						(376)
Transaction, reorganization, and separation						(22)
Financing costs, net						(514)
Income Before Income Taxes						$ 1,891
Total Assets[3]	$ 2,796	$ 2,199	$ 6,269	$ 1,698	$ 341	$ 13,303
Net Property and Equipment	$ 1,720	$ 1,646	$ 4,507	$ 187	$ 275	$ 8,335
Additions to Net Property and Equipment	$ 319	$ 159	$ 523	$ 3	$ 151	$ 1,155

(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, 2023, 2022, and 2021 of:

	For the Year Ended December 31,		
	2023	2022	2021
	(In millions)		
Oil	$ 729	$ 989	$ 420
Natural gas	95	117	47
Natural gas liquids	—	2	2

(2) Includes a noncontrolling interest in Egypt for all periods presented and a noncontrolling interest in Altus Midstream for the years 2022 and 2021.

(3) Intercompany balances are excluded from total assets.

(4) Exploration expense under Intersegment Eliminations & Other primarily reflects the Company’s Suriname exploration activities.

18. 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)				
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
2022					
Oil and gas production revenues	$ 4,144	$ 3,521	$ 1,558	$ —	$ 9,223
Operating cost:					
Depreciation, depletion, and amortization[2]	564	390	232	—	1,186
Asset retirement obligation accretion	34	—	82	—	116
Lease operating expenses	515	526	404	—	1,445
Gathering, processing, and transmission	315	22	43	—	380
Exploration expenses	24	84	35	162	305
Production taxes[3]	263	—	—	—	263
Income tax	510	1,100	495	—	2,105
	2,225	2,122	1,291	162	5,800
Results of operations	$ 1,919	$ 1,399	$ 267	$ (162)	$ 3,423
2021					
Oil and gas production revenues	$ 3,280	$ 2,085	$ 1,136	$ —	$ 6,501
Operating cost:					
Depreciation, depletion, and amortization[2]	511	477	267	—	1,255
Asset retirement obligation accretion	30	—	79	—	109
Lease operating expenses	391	469	383	—	1,243
Gathering, processing, and transmission	309	12	39	—	360
Exploration expenses	28	63	34	30	155
Production taxes[3]	188	—	—	—	188
Income tax	383	479	134	—	996
	1,840	1,500	936	30	4,306
Results of operations	$ 1,440	$ 585	$ 200	$ (30)	$ 2,195

(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 17—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 17—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)		
2023					
Acquisitions:					
Proved	$ 1	$ 4	$ —	$ —	$ 5
Unproved	20	—	—	—	20
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 and asset retirement costs:					
Capitalized interest	$ —	$ —	$ —	$ 24	$ 24
Asset retirement costs	(4)	—	375	—	371
2022					
Acquisitions:					
Proved	$ 596	$ 3	$ —	$ —	$ 599
Unproved	66	—	—	—	66
Exploration	4	169	61	311	545
Development	848	568	(57)	—	1,359
Costs incurred[1]	$ 1,514	$ 740	$ 4	$ 311	$ 2,569
[1] Includes capitalized interest and asset retirement costs:					
Capitalized interest	$ —	$ —	$ 1	$ 17	$ 18
Asset retirement costs	79	—	(215)	—	(136)
2021					
Acquisitions:					
Proved	$ —	$ (157)	$ —	$ —	$ (157)
Unproved	9	20	—	—	29
Exploration	6	86	39	170	301
Development	545	404	135	2	1,086
Costs incurred[1]	$ 560	$ 353	$ 174	$ 172	$ 1,259
[1] Includes capitalized interest, asset retirement costs, and Egypt modernization impacts as follows:					
Capitalized interest	$ —	$ —	$ —	$ 9	$ 9
Asset retirement costs	130	—	19	—	149
Egypt PSC modernization impacts – Proved and Unproved	—	(145)	—	—	(145)

[2] Includes a noncontrolling interest in Egypt.

In 2021, in connection with APA’s agreement to enter into a new merged concession agreement with EGPC, the Company recorded a reduction in proved properties totaling $165 million and an increase in unproved properties of $20 million, reflecting $247 million of incremental value due to the Company for the period between the effective date of April 1, 2021 and closing, partially offset by a $100 million signing bonus and $2 million of other post-closing adjustments.

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)		
2023					
Proved properties	$ 20,758	$ 13,777	$ 9,472	$ —	$ 44,007
Unproved properties	267	71	3	512	853
	21,025	13,848	9,475	512	44,860
Accumulated DD&A	(15,587)	(11,678)	(7,849)	—	(35,114)
	$ 5,438	$ 2,170	$ 1,626	$ 512	$ 9,746
2022					
Proved properties	$ 19,638	$ 13,014	$ 8,945	$ —	$ 41,597
Unproved properties	247	77	11	424	759
	19,885	13,091	8,956	424	42,356
Accumulated DD&A	(14,902)	(11,157)	(7,573)	—	(33,632)
	$ 4,983	$ 1,934	$ 1,383	$ 424	$ 8,724

(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	Total(1)
	(Thousands of barrels)			
Proved developed reserves:				
December 31, 2020	206,936	95,981	86,566	389,483
December 31, 2021	180,968	106,646	77,073	364,687
December 31, 2022	177,708	108,050	82,580	368,338
December 31, 2023	179,542	102,305	61,076	342,923
Proved undeveloped reserves:				
December 31, 2020	25,516	11,228	7,273	44,017
December 31, 2021	18,168	11,003	5,757	34,928
December 31, 2022	22,239	8,557	2,873	33,669
December 31, 2023	30,948	5,254	—	36,202
Total proved reserves:				
Balance December 31, 2020	232,452	107,209	93,839	433,500
Extensions, discoveries and other additions	17,869	13,390	2,288	33,547
Purchases of minerals in-place	126	—	—	126
Revisions of previous estimates	(4,479)	22,727	(60)	18,188
Production	(27,450)	(25,677)	(13,237)	(66,364)
Sales of minerals in-place	(19,382)	—	—	(19,382)
Balance December 31, 2021	199,136	117,649	82,830	399,615
Extensions, discoveries and other additions	9,776	7,580	2,616	19,972
Purchases of minerals in-place	16,362	—	—	16,362
Revisions of previous estimates	7,793	22,433	11,898	42,124
Production	(25,695)	(31,055)	(11,891)	(68,641)
Sales of minerals in-place	(7,425)	—	—	(7,425)
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

(1) Includes proved reserves of 36 MMbbls, 39 MMbbls, 39 MMbbls, and 36 MMbbls as of December 31, 2023, 2022, 2021, and 2020, respectively, attributable to a noncontrolling interest in Egypt.

	Natural Gas Liquids			
	United States	Egypt[(1)]	North Sea	Total[(1)]
	(Thousands of barrels)			
Proved developed reserves:				
December 31, 2020	150,599	716	2,053	153,368
December 31, 2021	164,172	446	2,059	166,677
December 31, 2022	158,745	—	2,230	160,975
December 31, 2023	153,486	—	1,460	154,946
Proved undeveloped reserves:				
December 31, 2020	15,141	126	320	15,587
December 31, 2021	16,380	30	275	16,685
December 31, 2022	19,004	—	76	19,080
December 31, 2023	18,401	—	—	18,401
Total proved reserves:				
Balance December 31, 2020	165,740	842	2,373	168,955
Extensions, discoveries and other additions	21,055	7	81	21,143
Purchases of minerals in-place	191	—	—	191
Revisions of previous estimates	22,724	(180)	318	22,862
Production	(24,175)	(193)	(438)	(24,806)
Sales of minerals in-place	(4,983)	—	—	(4,983)
Balance December 31, 2021	180,552	476	2,334	183,362
Extensions, discoveries and other additions	5,456	—	45	5,501
Purchases of minerals in-place	10,985	—	—	10,985
Revisions of previous estimates	9,991	(407)	333	9,917
Production	(22,895)	(69)	(406)	(23,370)
Sales of minerals in-place	(6,340)	—	—	(6,340)
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

(1) Includes proved reserves of 159 Mbbls and 281 Mbbls as of December 31, 2021 and 2020, respectively, attributable to a noncontrolling interest in Egypt.

	Natural Gas			
	United States	Egypt[1]	North Sea	Total[1]
	(Millions of cubic feet)			
Proved developed reserves:				
December 31, 2020	1,052,756	409,035	68,159	1,529,950
December 31, 2021	1,237,461	464,826	76,155	1,778,442
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
Proved undeveloped reserves:				
December 31, 2020	76,504	12,572	8,341	97,417
December 31, 2021	184,441	9,899	7,124	201,464
December 31, 2022	210,862	1,068	2,304	214,234
December 31, 2023	99,495	2,612	—	102,107
Total proved reserves:				
Balance December 31, 2020	1,129,260	421,607	76,500	1,627,367
Extensions, discoveries and other additions	227,684	50,209	3,684	281,577
Purchases of minerals in-place	839	—	—	839
Revisions of previous estimates	279,610	99,143	17,171	395,924
Production	(192,523)	(96,234)	(14,076)	(302,833)
Sales of minerals in-place	(22,968)	—	—	(22,968)
Balance December 31, 2021	1,421,902	474,725	83,279	1,979,906
Extensions, discoveries and other additions	38,157	10,191	1,643	49,991
Purchases of minerals in-place	70,584	—	—	70,584
Revisions of previous estimates	92,599	45,725	(3,431)	134,893
Production	(172,752)	(130,071)	(12,895)	(315,718)
Sales of minerals in-place	(73,410)	—	—	(73,410)
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

(1) Includes proved reserves of 127 Bcf, 134 Bcf, 158 Bcf, and 141 Bcf as of December 31, 2023, 2022, 2021, and 2020, respectively, attributable to a noncontrolling interest in Egypt.

	Total Equivalent Reserves			
	United States	Egypt(1)	North Sea	Total(1)
	(Thousands barrels of oil equivalent)			
Proved developed reserves:				
December 31, 2020	532,994	164,870	99,979	797,843
December 31, 2021	551,384	184,563	91,825	827,772
December 31, 2022	530,823	174,633	95,859	801,315
December 31, 2023	500,354	165,162	70,343	735,859
Proved undeveloped reserves:				
December 31, 2020	53,408	13,449	8,983	75,840
December 31, 2021	65,288	12,683	7,219	85,190
December 31, 2022	76,386	8,735	3,333	88,454
December 31, 2023	65,931	5,690	—	71,621
Total proved reserves:				
Balance December 31, 2020	586,402	178,319	108,962	873,683
Extensions, discoveries and other additions	76,871	21,765	2,983	101,619
Purchases of minerals in-place	457	—	—	457
Revisions of previous estimates	64,847	39,071	3,120	107,038
Production	(83,712)	(41,909)	(16,021)	(141,642)
Sales of minerals in-place	(28,193)	—	—	(28,193)
Balance December 31, 2021	616,672	197,246	99,044	912,962
Extensions, discoveries and other additions	21,592	9,278	2,935	33,805
Purchases of minerals in-place	39,110	—	—	39,110
Revisions of previous estimates	33,217	29,647	11,659	74,523
Production	(77,382)	(52,803)	(14,446)	(144,631)
Sales of minerals in-place	(26,000)	—	—	(26,000)
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

(1) Includes total proved reserves of 57 MMboe, 61 MMboe, 66 MMboe, and 59 MMboe as of December 31, 2023, 2022, 2021, and 2020, respectively, attributable to a noncontrolling interest in Egypt.

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, offset by engineering and performance upward revisions of 37 MMboe.

During 2022, the Company added approximately 34 MMboe from extensions, discoveries, and other additions. The Company recorded 22 MMboe of exploration and development adds in the U.S., comprising 9 MMboe in the Permian Basin, 8 MMboe in the Texas Gulf Coast, and 5 MMboe in the Delaware Basin. 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 12 MMboe of exploration and development adds, with Egypt contributing 9 MMboe from onshore exploration and appraisal activity primarily in the Khalda Area and 3 MMboe from the North Sea. The Company had combined upward revisions of previously estimated reserves of 75 MMboe. Upward revisions related to miscellaneous changes accounted for 5 MMboe. Engineering and performance upward revisions accounted for 70 MMboe, with Egypt accounting for an increase of 43 MMboe, primarily the result of PSC modernization in Egypt. The North Sea contributed 9 MMboe of upward revisions from well performance and reactivations in both the Beryl and Forties programs. In the United States, the Company experienced positive revisions of 18 MMboe. The Company acquired 39 MMboe of proved reserves during 2022, primarily in the Delaware Basin. The Company also sold 26 MMboe of proved reserves associated with U.S. divestitures, primarily related to Permian Basin assets.

During 2021, the Company added approximately 102 MMboe from extensions, discoveries, and other additions. The Company recorded 77 MMboe of exploration and development adds in the U.S., comprising 59 MMboe in the Permian Basin with the remaining 18 MMboe in the Texas Gulf Coast. The Permian Basin drilling programs targeted the Woodford, Barnett, Bone Springs, and Spraberry, while the Texas Gulf Coast focused on the Austin Chalk. International operations contributed 25 MMboe of exploration and development adds, with Egypt contributing 22 MMboe from onshore exploration and appraisal activity primarily in the Khalda Area concession post-PSC modernization. The North Sea contributed 3 MMboe. The Company had combined upward revisions of previously estimated reserves of 107 MMboe. Upward revisions related to changes in product prices accounted for 85 MMboe. Engineering and performance upward revisions accounted for 22 MMboe, with the new merged concession agreement in Egypt resulting in an increase of 57 MMboe, partially offset by other downward revisions of 35 MMboe across all of the Company’s geographic areas of operation. The Company also sold 28 MMboe of proved reserves associated with U.S. divestitures, primarily related to Permian Basin assets.

The impact of the consolidated PSC to proved reserves based on the modernized terms was an estimated increase of 53 MMboe and 4 MMboe in developed and undeveloped reserves, respectively, and approximately $750 million in discounted future net cash flows. As of December 31, 2021, approximately 96 percent of the Company’s Egypt reserves were consolidated within the modernized PSC. These estimates include Sinopec’s noncontrolling interest in Egypt.

Approximately 10 percent of the Company’s year-end 2023 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 18, under “Future Net Cash Flows.”

Future Net Cash Flows

Future cash inflows as of December 31, 2023, 2022, and 2021 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, 2023, 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	Total(1)
		(In millions)		
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
2022				
Cash inflows	$ 31,577	$ 12,819	$ 10,147	$ 54,543
Production costs	(10,763)	(2,086)	(3,241)	(16,090)
Development costs	(1,733)	(1,471)	(2,297)	(5,501)
Income tax expense	(1,575)	(2,729)	(2,631)	(6,935)
Net cash flows	17,506	6,533	1,978	26,017
10 percent discount rate	(6,811)	(1,400)	(204)	(8,415)
Discounted future net cash flows(2)	$ 10,695	$ 5,133	$ 1,774	$ 17,602
2021				
Cash inflows	$ 22,852	$ 9,337	$ 6,832	$ 39,021
Production costs	(8,323)	(1,712)	(2,343)	(12,378)
Development costs	(1,632)	(1,402)	(2,533)	(5,567)
Income tax expense	(134)	(1,887)	(768)	(2,789)
Net cash flows	12,763	4,336	1,188	18,287
10 percent discount rate	(5,294)	(983)	350	(5,927)
Discounted future net cash flows(2)	$ 7,469	$ 3,353	$ 1,538	$ 12,360

(1) Includes discounted future net cash flows of approximately $1.3 billion, $1.7 billion, and $1.1 billion as of December 31, 2023, 2022, and 2021, 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 $13.6 billion, $22.6 billion, and $14.9 billion as of December 31, 2023, 2022, and 2021, respectively.

The following table sets forth the principal sources of change in the discounted future net cash flows:

	For the Year Ended December 31,		
	2023	2022	2021
		(In millions)	
Sales, net of production costs	$ (5,408)	$ (7,131)	$ (4,707)
Net change in prices and production costs	(7,089)	8,690	9,376
Discoveries and improved recovery, net of related costs	1,869	1,142	1,749
Change in future development costs	(413)	(343)	(839)
Previously estimated development costs incurred during the period	825	669	545
Revision of quantities	(262)	2,646	1,983
Purchases of minerals in-place	1	911	1
Accretion of discount	2,260	1,489	626
Change in income taxes	1,467	(2,467)	(1,583)
Sales of minerals in-place	(18)	(363)	(116)
Change in production rates and other	(793)	(1)	13
	$ (7,561)	$ 5,242	$ 7,048