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, 2022

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 **1-4300**

APACHE CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**41-0747868**
(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: None

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 ☐

Note: The registrant is a voluntary filer of reports required to be filed by certain companies under Sections 13 or 15(d) of the Securities Exchange Act of 1934.

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, 2022	N/A
Number of shares of registrant's common stock outstanding as of January 31, 2022 (100% owned by APA Corporation)	1,000

OMISSION OF CERTAIN INFORMATION

The registrant meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing this Annual Report on Form 10-K with the reduced disclosure format.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of APA Corporation’s proxy statement relating to its 2023 annual meeting of stockholders (the APA Proxy Statement) have been incorporated by reference into Part III hereof.

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FORWARD-LOOKING STATEMENTS AND RISKS

This Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical facts included or incorporated by reference in this Annual Report on Form 10-K, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected revenues, projected costs, and plans and objectives of management for future operations, 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, 2022, 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 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;
- terrorism or cyberattacks;
- the occurrence of property acquisitions or divestitures;
- the integration of acquisitions;
- the Company's ability to access the capital markets;
- market-related risks, such as general credit, liquidity, and interest-rate risks;
- the Company's expectations with respect to the new operating structure implemented pursuant to the Holding Company Reorganization (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) and the associated disclosure implications; 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 Narrative Analysis of 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 “Apache,” the “Company,” “we,” “us,” and “our” refer to Apache Corporation and its consolidated subsidiaries, unless otherwise specifically stated. References to “APA” refer to APA Corporation, the Company’s parent holding company, and its consolidated subsidiaries, including the Company, unless otherwise specifically stated.

PART I

ITEMS 1 and 2. *BUSINESS AND PROPERTIES*

GENERAL

Apache Corporation, a direct, wholly owned subsidiary of APA Corporation (APA), is an independent energy company that explores for, develops, and produces natural gas, crude oil, and NGLs. The Company's upstream business currently has exploration and production operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea (North Sea). 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). Altus owned, developed, and operated a midstream energy asset network in the Permian Basin of West Texas.

On March 1, 2021, the Company consummated a holding company reorganization (the Holding Company Reorganization), pursuant to which the Company became a direct, wholly owned subsidiary of APA, and all of the Company's outstanding shares automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to the Company pursuant to Rule 12g-3(a) under the Exchange Act and replaced the Company as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized APA's operating and legal structure to more closely align with its growing international presence, making it more consistent with other companies that have affiliates operating around the globe. Refer to Note 2—Transactions with Parent Affiliate in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K for more detail.

Through APA's website, www.apacorp.com, you can access, free of charge, electronic copies of the 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. 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, 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, APA also posts announcements, updates, and investor information on its website in addition to copies of all recent press releases. Information on APA'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.

Certain properties referred to herein may be held by subsidiaries of Apache Corporation.

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

Apache has exploration and production operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea.

The following table sets out a brief comparative summary of certain key 2022 data for each of Apache'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	73.9	52 %	$ 3,949	573	67 %	74	74
Egypt[1]	52.8	38 %	3,521	184	21 %	97	82
North Sea[2]	14.4	10 %	1,558	99	12 %	2	2
Total	141.1	100 %	$ 9,028	856	100 %	173	158

(1) Apache's operations in Egypt, excluding the impacts of noncontrolling interests contributed 22 percent of 2022 production and accounted for 11 percent of year-end estimated proved reserves.

(2) Sales volumes from the Company's North Sea assets for 2022 were 14.9 MMboe. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

United States

In 2022, Apache's U.S. upstream oil and gas operations contributed approximately 52 percent of production, 44 percent of oil and gas revenues, and 67 percent of estimated year-end proved reserves, consistent with prior years. Apache has access to significant liquid hydrocarbons across its 3.5 million gross acres (1.7 million net acres) in the U.S., 74 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. Apache is one of the largest operators in the Permian Basin, operating approximately 6,000 gross oil and gas wells across its acreage, with additional interests in more than 3,000 non-operated wells. Of note, approximately six percent of the Company's net acreage position in the Permian Basin is on federal onshore lands. Apache 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* Apache holds approximately 789,000 gross acres (451,000 net acres) in the Southern Midland Basin and the Eagle Ford shale and Austin Chalk areas of southeast Texas. During 2022, the Company averaged two rigs targeting oil plays in the Wolfcamp and Spraberry formations, drilling 52 gross development wells in this basin with a 100 percent success rate.
- *Delaware Basin* Apache holds approximately 223,000 gross acres (127,000 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 2022, the Company completed 22 gross development wells with a 100 percent success rate.
- *Legacy Assets* Apache holds approximately 2.5 million gross acres (1.1 million net acres) in legacy properties, of which 663,000 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* Apache separately has undeveloped acreage positions across several states where it intends to pursue exploration interests and potential development opportunities over time.

The Company is committed to maintaining a safe, steady, and efficient level of activity as part of its three-year capital investment program. For 2023, 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 beginning in 2023, the Company will purchase 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. Apache strives to maintain a diverse client portfolio, which is intended to reduce the concentration of credit risk.

Apache 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. Apache'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.

Apache'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 Apache to deliver an average of 181 Bcf of natural gas per year for the period from 2023 through 2029, an average of 53 Bcf of natural gas per year for the period from 2030 through 2037, and an average of 5.7 MMbbls of crude oil per year for the period from 2023 through 2025, in each case, at variable, domestic and/or international, market-based pricing.

Apache currently expects to fulfill its delivery commitments with production from its proved reserves, production from continued development and/or third-party purchases. Apache 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 2022, international assets contributed 48 percent of Apache's production and 56 percent of its oil and gas revenues. Approximately 33 percent of estimated proved reserves at year-end were located outside the U.S.

Apache 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.

Egypt Apache has 27 years of exploration, development and operations experience in Egypt and is one of the largest acreage holders in Egypt's Western Desert. At year-end 2022, 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 merged concession agreement (MCA) with the Egyptian government, as more fully described below. 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 68 percent of the Company's gross acreage in Egypt is undeveloped, providing Apache with considerable exploration and development opportunities for the future.

Apache'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 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 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 Apache's Egypt operations despite impacting Apache's production and reserves.

On December 27, 2021, the Company announced the ratification of a new MCA with EGPC having an effective date of April 1, 2021. The MCA consolidated 98 percent of gross acreage and 90 percent of gross production under one concession agreement and refreshed the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool to provide improved access to cost recovery, a fixed 40 percent cost recovery limit, and a fixed profit-sharing rate of 30 percent for all Apache production covered under the new concession.

Sinopec International Petroleum Exploration and Production Corporation (Sinopec) owns a one-third minority participation in the Company's consolidated Egypt oil and gas business. In conjunction with the ratification of the MCA with EGPC, Apache entered into an agreement with APA under which the historical value of existing concessions prior to ratifying the MCA was retained by Apache, with any excess value from the MCA terms being allocated to APA. In accordance with terms of the agreement, approximately 30 percent of the Company's Egyptian operation net income and distributable cash flow, excluding Sinopec's one-third interest, was allocated to APA during 2022.

The Company's estimated proved reserves in Egypt are reported under the economic interest method and exclude the host country's share of reserves. Apache's Egypt assets, including APA and Sinopec's noncontrolling interests, contributed 38 percent of 2022 production and 21 percent of 2022 year-end estimated proved reserves. Excluding the impacts of APA and Sinopec's noncontrolling interests, Egypt contributed 22 percent of 2022 production and 11 percent of 2022 year-end estimated proved reserves.

In 2022, the Company drilled 66 gross development and 31 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 Apache'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.

During 2022, the Company focused on several environmental initiatives in Egypt and has delivered on its 2022 upstream flaring reduction goal by flaring at least 40 percent less gas than would otherwise be flared without these initiatives, with the Company now compressing this gas into sales lines.

For 2023, the Company will continue to focus on driving efficiencies and managing costs after increasing activity under the MCA.

North Sea Apache has interests in approximately 294,000 gross acres in the U.K. North Sea. These assets contributed 10 percent of Apache's 2022 production and approximately 11 percent of year-end estimated proved reserves.

Apache entered the North Sea in 2003 after acquiring an approximate 97 percent working interest in the Forties field (Forties). Since acquiring Forties, Apache has actively invested in these assets and has established a large inventory of drilling prospects through successful exploration programs and the interpretation of 4-D seismic. Building upon its success in Forties, in 2011 Apache acquired Mobil North Sea Limited, providing the Company with additional exploration and development opportunities in the North Sea across numerous fields, including operated interests in the Beryl, Ness, Nevis, Nevis South, Skene, and Buckland fields and a non-operated interest in the Maclure field. Apache also has a non-operated interest in the Nelson field acquired in 2011. The Beryl field, which is a geologically complex area with multiple fields and stacked pay potential, provides for significant exploration opportunity.

During 2022, Apache averaged two rigs in the North Sea and drilled one gross development well and one gross exploration well. Production was negatively impacted by considerable planned and unplanned downtime at Beryl and Forties during 2022, improving in the fourth quarter of 2022 following completion of these maintenance activities.

International Marketing Apache'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.

Apache'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.

Drilling Statistics

Worldwide in 2022, Apache drilled or participated in drilling 173 gross wells, with 158 wells (91 percent) completed as producers. Historically, Apache'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 2022, at year-end a number of wells had not yet reached completion: 89 gross (74.2 net) in the U.S., 41 gross (40.7 net) in Egypt, and 1 gross (0.6 net) in the North Sea.

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
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
Total	16.0	14.5	30.5	106.1	—	106.1	122.1	14.5	136.6
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
Total	10.6	14.5	25.1	98.2	1.5	99.7	108.8	16.0	124.8
2020									
United States	—	—	—	46.3	0.8	47.1	46.3	0.8	47.1
Egypt	17.7	7.0	24.7	35.7	—	35.7	53.4	7.0	60.4
North Sea	0.6	1.0	1.6	4.2	0.6	4.8	4.8	1.6	6.4
Other International	—	1.5	1.5	—	—	—	—	1.5	1.5
Total	18.3	9.5	27.8	86.2	1.4	87.6	104.5	10.9	115.4

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, 2022, is set forth below:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
United States	8,716	5,260	881	624	9,597	5,884
Egypt	1,076	1,037	116	113	1,192	1,150
North Sea	159	116	13	8	172	124
Total	9,951	6,413	1,010	745	10,961	7,158
Domestic	8,716	5,260	881	624	9,597	5,884
Foreign	1,235	1,153	129	121	1,364	1,274
Total	9,951	6,413	1,010	745	10,961	7,158

Gross natural gas and crude oil wells included 514 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)
2022							
United States	24.1	21.9	167.6	$ 10.96	$ 96.25	$ 33.47	$ 5.33
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	67.1	22.4	310.5	12.75	99.39	34.62	4.97
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
2020							
United States	32.3	27.1	205.6	$ 7.39	$ 37.42	$ 11.21	$ 1.22
Egypt[1]	27.6	0.3	100.4	10.35	39.95	27.83	2.79
North Sea[2]	18.4	0.7	21.0	15.60	42.88	29.73	3.19
Total	78.3	28.1	327.0	9.37	39.60	11.84	1.83

(1) Includes production volumes attributable to noncontrolling interests in Egypt.

(2) Sales volumes from the Company's North Sea assets for 2022, 2021, and 2020 were 14.9 MMboe, 16.1 MMboe, and 22.7 MMboe, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

Gross and Net Undeveloped and Developed Acreage

The following table summarizes the Company's gross and net acreage position as of December 31, 2022:

	Undeveloped Acreage		Developed Acreage	
	Gross Acres	Net Acres	Gross Acres	Net Acres
	(In thousands)			
United States	2,616	1,166	913	561
Egypt	3,589	3,589	1,711	1,661
North Sea	135	118	159	123
Total	6,340	4,873	2,783	2,345

As of December 31, 2022, Apache held 10,000 net undeveloped acres that are scheduled to expire by year-end 2023 if production is not established or the Company takes no action to extend the terms. The Company also held 118,000 and 12,000 net undeveloped acres set to expire by year-end 2024 and 2025, respectively. 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.

Exploration concessions in the Company's Egypt asset were extended upon ratification of the new merged concession agreement with the EGPC, and no acreage is scheduled to expire over the next three years. The Company will continue to pursue acreage extensions and access to new concessions in areas in which it believes exploration opportunities exist.

As of December 31, 2022, approximately 97 percent of U.S. net undeveloped acreage was held by production or owned as undeveloped mineral rights.

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, Apache 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. Apache 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, 2022, based on average commodity prices in effect on the first day of each month in 2022, 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	169	153	1,128	510
Egypt(1)	108	—	400	175
North Sea	83	2	66	96
Total	360	155	1,594	781
Proved Undeveloped:				
United States	16	16	189	64
Egypt(1)	9	—	1	9
North Sea	3	—	2	3
Total	28	16	192	76
Total Proved	388	171	1,786	857

(1) Includes total proved developed and total proved undeveloped reserves of 94 MMboe and 5 MMboe, respectively, attributable to noncontrolling interests in Egypt.

As of December 31, 2022, Apache had total estimated proved reserves of 388 MMbbls of crude oil, 171 MMbbls of NGLs, and 1.8 Tcf of natural gas. Combined, these total estimated proved reserves are the volume equivalent of 857 million boe, of which liquids represents approximately 65 percent. As of December 31, 2022, the Company's proved developed reserves totaled 781 MMboe and estimated PUD reserves totaled 76 MMboe, or approximately 9 percent of worldwide total proved reserves. Apache has elected not to disclose probable or possible reserves in this filing. The Company has one field that contains 15 percent or more of its total proved reserves for the years ended December 31, 2022, 2021, and 2020.

During 2022, the Company added 34 MMboe of proved reserves through exploration and development activity. There were also 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 the new merged concession agreement in Egypt accounting for an increase of 43 MMboe. The North Sea contributed upward revisions of 9 MMboe 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 1 MMboe of proved reserves and sold 26 MMboe of proved reserves associated with U.S. divestitures, primarily related to the Permian Basin.

The Company's estimates of proved reserves, proved developed reserves, and PUD reserves as of December 31, 2022, 2021, and 2020, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Note 19—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 76 MMboe as of December 31, 2022, decreased by 9 MMboe from 85 MMboe of PUD reserves reported at year end 2021. During the year, Apache converted 20 MMboe of PUD reserves to proved developed reserves through development drilling activity. In the U.S., Apache converted 13 MMboe, with the remaining 7 MMboe in its international areas. Apache sold 0.4 MMboe of PUD reserves in the U.S. and did not acquire any PUD reserves during 2022. Apache added 14 MMboe of new PUD reserves through extensions and discoveries. Downward revisions totaled 5 MMboe, comprising 0.5 MMboe associated with engineering and interest revisions, 4 MMboe associated with revised development plans, and 0.5 MMboe associated with product prices.

During 2022, a total of approximately $215 million was spent on projects associated with proved undeveloped reserves. A portion of Apache's costs incurred each year relate to development projects that will convert undeveloped reserves to proved developed reserves in future years. During 2022, Apache spent approximately $105 million on PUD reserve development activity in the U.S. and $110 million in the international areas. As of December 31, 2022, Apache 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

Apache'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.

Apache'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 Apache'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 Apache's board of directors (the 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.

Apache'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 2022, the properties selected for each country ranged from 81 to 84 percent of the total future net cash flows discounted at 10 percent. These properties also accounted for 83 percent of the value of Apache's international proved reserves and 96 percent of the value of Apache'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 80 percent of total proved reserves on a boe basis.

The percentages of total estimated proved reserves and volumes covered by Ryder Scott's reviews for the years 2022, 2021, and 2020 were:

	2022	2021	2020
Estimated proved reserves values	82 %	83 %	85 %
Estimated proved reserves volumes:			
United States	80 %	80 %	80 %
Egypt	80 %	80 %	82 %
North Sea	81 %	81 %	83 %
Apache Worldwide	80 %	80 %	81 %

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 Apache, the overall procedures and methodologies utilized by Apache in determining the proved reserves comply with the current SEC regulations, and the overall proved reserves for the reviewed properties as estimated by Apache 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 Apache'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, Apache'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, Apache'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, Apache 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. Subsequent to the close of the transaction, in March 2022, the Company sold four million of its shares of Kinetik Class A Common Stock for $224 million, reducing the Company's retained ownership percentage in Kinetik to approximately 13 percent. Upon closing the transaction, the Company no longer consolidated the assets and liabilities of ALTM in its consolidated financial statements.

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 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. During 2020, sales to EGPC and Vitol accounted for approximately 17 percent and 14 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.

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 2022, the Company maintained offices in Midland, Texas; Houston, Texas; Cairo, Egypt; and Aberdeen, Scotland. Apache'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 12—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

Apache and its wholly owned subsidiary, Apache Deepwater LLC (ADW), developed oil spill response plans (the Plans) for their respective offshore operations in the Gulf of Mexico and the North Sea, 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.

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. Apache also has a contract for response resources and services with National Response Corporation (NRC). NRC is the world's largest commercial Oil Spill Response Organization and is the global leader in providing end-to-end environmental, industrial, and emergency response solutions with operating bases in 13 countries. 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 and ADW. Both Apache and ADW are members 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 was created to provide a means of effectively staging response equipment and to provide spill response capability for its member companies operating in the Gulf of Mexico. CGA equipment includes skimming vessels, barges, boom, and dispersants.

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 relating to the Company's securities may be included in the prospectus supplements related to offerings of such securities from time to time in the future.

RISKS RELATED TO PRICING, DEMAND, AND PRODUCTION FOR CRUDE OIL, NATURAL GAS, AND NGLs

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, and the demand for and prices of oil, natural gas, and NGLs.

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. Previous business closures, restrictions on travel, "stay-at-home" or "shelter-in-place" orders, and other restrictions on movement within and among communities significantly reduced demand for, and the prices of, oil, natural gas, and NGLs, and such restrictions may be continued or reintroduced at any time. A continued, prolonged period or a renewed period of reduced demand, the failure to timely distribute or the ineffectiveness of or reluctance or refusal of individuals to take any vaccines, the failure to develop or reformulate adequate treatments, including due to the emergence of new variants, and other adverse impacts from a pandemic may materially adversely affect the Company's business, financial condition, cash flows, and results of operations. Actual results will depend on future events, which the Company cannot predict, including the scope, duration, and potential reoccurrence of any such pandemic, the emergence and impact of variants, the distribution and effectiveness of, and individual willingness to take, vaccines, therapeutics, and treatments, the demand for, and the prices of, oil, natural gas, and NGLs, and the actions taken by third parties in response to any of the foregoing.

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.

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

The Company's revenues, operating results, and future rate of growth 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 2022 ranged from a high of $123.64 per barrel to a low of $71.05 per barrel, and the NYMEX daily settlement price for the prompt month natural gas contract in 2022 ranged from a high of $9.85 per MMBtu to a low of $3.46 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;
- 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 (including instabilities, changes in governments, or armed conflicts) in oil and gas producing regions;
- the occurrence of global events, such as epidemics or pandemics (including, specifically, the COVID-19 pandemic), and the actions taken by third parties, including, but not limited to, governmental authorities, customers, contractors, and suppliers, in response to such epidemics or pandemics;
- the price and level of imported foreign or exported domestic crude oil, natural gas, and NGLs, including as a result of the availability of facilities that process, import, or export such products;
- increasing inflationary pressure;
- the price and availability of alternative fuels, including coal and biofuels;

- 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 and other stakeholders on decisions and policies related to the industries in which the Company and its affiliates operate, including with respect to environmental, social, and governance matters;
- domestic and foreign governmental regulations and taxes, including legislative, regulatory, and policy changes or initiatives to address the impacts of global climate change, hydraulic fracturing, methane emissions, flaring, or water disposal; and
- the overall economic environment.

The Company's results of operations, as well as the carrying value of its oil and gas properties, are substantially dependent upon the prices of oil, natural gas, and NGLs. Low prices have previously adversely affected and could again adversely affect the Company's revenues, operating income, cash flow, and proved reserves, and continued low prices could have a material adverse impact on the Company's operations 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 may further adversely impact the Company's business as follows:

- weakening the Company's financial condition and reducing its liquidity;
- limiting the Company's ability to fund planned capital expenditures and operations;
- reducing the amount of crude oil, natural gas, and NGLs that the Company can produce economically;
- causing the Company to delay or postpone some of its capital projects or reallocate capital to different projects or regions;
- reducing the Company's revenues, operating income, and cash flows;
- limiting the Company's access to sources of capital, such as equity and long-term debt;
- reducing the carrying value of the Company's oil and gas properties, resulting in additional non-cash impairments; or
- reducing the carrying value of the Company's gathering, processing, and transmission facilities, resulting in additional 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 the risk that the Company will not encounter commercially productive oil or gas reservoirs. The wells the Company drills or participates in may not be productive, and the Company may not recover all or any portion of its investment in those wells. Management has previously determined, and may in the future determine, that future or further 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, including drilling results in, or information related to, adjacent or nearby geographic areas or similar geologies or reservoirs. The seismic data and other technologies that the Company uses do not allow it to know conclusively prior to drilling a well that crude or natural gas is present or may be produced economically. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including, but not limited to, unexpected drilling conditions; pressure or irregularities in formations; equipment failures or accidents; fires, explosions, blowouts, and surface cratering; marine risks, such as capsizing, collisions, and hurricanes; other adverse weather conditions; and increases in the cost of or shortages or delays in the availability of drilling rigs, equipment, and labor.

Future drilling activities may not be successful, and, if unsuccessful, such failure could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. 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 above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which the Company's production falls short of the hedged volumes, there is a widening of price-basis differentials between delivery points for the Company's production and the delivery point assumed in the hedge arrangement, the counterparties to the Company's hedging or other price risk management contracts fail to perform under those arrangements, or an unexpected event materially impacts commodity prices.

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 equipment, 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, and cratering; pipeline or other facility ruptures and spills; formations with abnormal pressures; equipment malfunctions; hurricanes, major storms, and cyclones, which could affect the Company's operations in areas such as on and offshore the Gulf Coast and the North Sea, and other natural and anthropogenic disasters and weather conditions; and surface spillage and surface or ground water contamination from petroleum constituents, saltwater, or hydraulic fracturing chemical additives.

Failure or loss of equipment, as the result of equipment malfunctions, cyberattacks, or natural disasters, such as hurricanes, could result in property damages, personal injury, environmental pollution, and other damages for which the Company could be liable. Litigation arising from a catastrophic occurrence, such as a well blowout, explosion, fire at a location where the Company's equipment and services are used, or ground water contamination from chemical additives used in hydraulic fracturing may result in substantial claims for damages. Ineffective containment of a drilling well blowout or pipeline rupture or surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing could result in extensive environmental pollution and substantial remediation expenses. 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, 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 can be hazardous, involving natural disasters and other events such as blowouts, cratering, fires, explosions, and loss of well control, 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 risk. 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.

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

The Company's business has become increasingly dependent on digital technologies to conduct certain exploration, development, and production activities. The Company depends on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate with personnel and third-party partners, and conduct many of the Company's activities. Unauthorized access to the Company's digital technology could lead to operational disruption, data corruption, communication interruption, loss of intellectual property, loss of confidential and fiduciary data, and loss or corruption of reserves or other proprietary information. Also, external digital technologies control nearly all of 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. A cyberattack directed at oil and gas distribution systems have previously and could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets, and make it difficult or impossible to accurately account for production and settle transactions. Any such terrorist attack, environmental activist group activity, or cyberattack that affects the Company or its customers, suppliers, or others with whom it does business 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 certain of the Company's insurance policies may allow for coverage of associated damages resulting from such events, if the Company were to incur a significant liability for which it was not fully insured, that could have a material adverse effect on the Company's financial position, results of operations, and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

While the Company has experienced cyberattacks in the past, it has not suffered any material losses as a result of such attacks; however, there is no assurance that the Company will not suffer such losses in the future. Further, as cyberattacks continue to evolve, the Company may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any vulnerabilities to cyberattacks. In addition, cyberattacks against the Company or others in its industry could result in additional regulations, which could lead to increased regulatory compliance costs, insurance coverage cost, or capital expenditures. The Company cannot predict the potential impact that such additional regulations could have on its business and operations or the energy industry at large.

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 may adversely affect the Company's large development projects and its ability to participate in large-scale development projects in the future. In addition, the Company's estimates of future development costs are based on its current expectations of prices and other costs of equipment and personnel the Company will need to implement such projects. The actual future development costs may be significantly higher than the Company currently estimates. If costs become too high, the development projects may become uneconomic to the Company, and it may be forced to abandon such development projects.

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, unless the Company adds reserves through exploration and development activities, identifies additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves through engineering studies, or acquires additional properties containing proved reserves, the Company's estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon the Company's level of success in acquiring or finding additional reserves on an economic basis. Furthermore, 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. It generally is not feasible to review in-depth every individual property involved in each acquisition. Ordinarily, the Company will focus its review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit the Company as a buyer to become sufficiently familiar with the properties to assess fully and accurately their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Company often assumes certain environmental and other risks and liabilities in connection with acquired properties. 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. In addition, there can be no assurance that acquisitions will not have an adverse effect upon the Company's operating results, particularly during the periods in which the operations of acquired businesses are being integrated 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 estimating crude oil, natural gas, and NGL reserves and their value. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas, and NGLs that cannot be measured in an exact manner. Because of the high degree of judgment involved, the accuracy of any reserve estimate is inherently imprecise and a function of the quality of available data and the engineering and geological interpretation. The Company's reserves estimates are based on 12-month average prices, except where contractual arrangements exist; therefore, reserves quantities will change when actual prices increase or decrease. In addition, results of drilling, testing, and production may substantially change the reserve estimates for a given reservoir over time. 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 effects of regulations by governmental agencies, including changes to severance and excise taxes, future operating costs and capital expenditures, and workover and remediation costs.

For these reasons, estimates of the economically recoverable quantities of crude oil, natural gas, and NGLs attributable to any particular group of properties, classifications of those reserves, and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserves estimates may be subject to upward or downward adjustment, and actual production, revenue, and expenditures with respect to the Company's reserves likely will vary, possibly materially, from estimates.

Additionally, because some of the Company's reserves estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. 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.

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. These transactions expose the Company to credit risk in the event of default of the counterparty. Deterioration in the credit or financial markets may impact the credit ratings of the Company's current and potential counterparties and affect their ability to fulfill their existing obligations to the Company and their willingness to enter into future transactions with the Company. The Company may also have exposure to financial institutions in the form of derivative transactions in connection with any hedges. The Company also has exposure to insurance companies in the form of claims under the Company's policies. In addition, if any lender under the Company's credit facilities is unable to fund its commitment, the Company's liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under the credit facilities.

The Company is exposed to a risk of financial loss if a counterparty fails to perform under a derivative contract. This risk of counterparty non-performance is of particular concern given the recent volatility of the financial markets and significant changes in commodity prices, which could lead to sudden changes in a counterparty's liquidity and impair its ability to perform under the terms of the derivative contract. The Company is unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if the Company does accurately predict sudden changes, its ability to negate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of the Company's hedge providers 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. During periods of falling commodity prices, the Company's hedge receivable positions increase, which increases the Company's exposure. If the creditworthiness of the counterparties deteriorates and results in their nonperformance, 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.

Concerns about global economic conditions and the volatility of oil, natural gas, and NGL prices have had a significant adverse impact on the oil and gas industry. The Company is exposed to risk of financial loss from trade, joint venture, joint interest billing, and other receivables. The Company sells its crude oil, natural gas, and NGLs to a variety of purchasers. As operator, the Company pays expenses and bills its non-operating partners for their respective shares of costs. As a result of recent economic conditions and the previously severe decline in commodity prices, some of the Company's customers and non-operating partners experienced severe financial problems that had a significant impact on their creditworthiness. 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 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. Furthermore, the bankruptcy of one or more of the Company's customers or non-operating partners or some other similar proceeding or liquidity constraint have made it and might make it unlikely that the Company will or would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. Nonperformance by a trade creditor or non-operating partner could result in significant financial losses.

The Company's liabilities could be adversely affected in the event one or more of its transaction counterparties become the subject of a bankruptcy case.

From time to time the Company divests noncore or nonstrategic domestic and international assets. The agreements relating to these transactions contain provisions pursuant to which liabilities related to past and future operations have been allocated between the parties by means of liability assumptions, indemnities, escrows, trusts, bonds, letters of credit, and similar arrangements. One of the most significant of these liabilities involves the decommissioning of wells and facilities previously owned by the Company. One or more of the counterparties in these transactions could fail to perform its obligations under these agreements as a result of financial distress. In the event that any such counterparty becomes the subject of a case or proceeding under Title 11 of the United States Code or any other relevant insolvency law or similar law (which are collectively referred to as Insolvency Laws), the counterparty may not perform its obligations under the agreements related to these transactions. In that case, the Company's remedy in the proceeding would be a claim for damages for the breach of the contractual arrangements, which may be either a secured claim or an unsecured claim depending on whether or not the Company has collateral from the counterparty for the performance of the obligations. Resolution of the Company's claim for damages in such a proceeding may be delayed, and the Company may be forced to use available cash to cover the costs of the obligations assumed by the counterparties under such agreements should they arise, pending final resolution of the proceeding.

Despite the provisions in the Company's agreements requiring purchasers of its state or federal leasehold interests to assume certain liabilities and obligations related to such interests, if a purchaser of such interests becomes the subject of a case or proceeding under relevant Insolvency Laws or becomes unable financially to perform such liabilities or obligations, the Company would expect the relevant governmental authorities to require it to perform and hold it responsible for such liabilities and obligations. In such event, the Company may be forced to use available cash to cover the costs of such liabilities and obligations should they arise.

If a court or a governmental authority were to make any of the foregoing determinations or take any of the foregoing actions, or any similar determination or action, it 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 12—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. There is risk that 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 2022, the Company's credit rating was affirmed by Moody's as Ba1/Positive and by Standard and Poor's 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 shocks. 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.

APA Corporation's syndicated 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 APA, the Company, or APA's other subsidiaries or the composition of such lenders.

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, both domestically and internationally, have campaigned for governmental and private action to influence change in the business strategies in 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 activities include increasing attention and demands for action related to climate change and energy transition matters, such as promoting the use of substitutes to fossil fuel products and encouraging the divestment of investments in the oil and gas industry, as well as pressuring 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

Future economic conditions in the U.S. and international markets may materially adversely impact the Company's operating results.

Current global market conditions and uncertainty, including economic instability in emerging markets, are likely to have significant long-term effects on the Company's operating results. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for the Company's oil and natural gas production as well as lower commodity prices, which would reduce the Company's cash flows from operations and its profitability.

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 with major integrated and other independent oil and gas companies for acquisitions of oil and gas leases, properties, and reserves, equipment and labor required to explore, develop, and operate those properties, and marketing of crude oil, natural gas, and NGL production. Crude oil, natural gas, and NGL prices impact the costs of properties available for acquisition and the number of companies with the financial resources to pursue acquisition opportunities. Many of the Company's competitors have financial and other resources substantially larger than the Company possesses and 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 drilling rights. In addition, many of the Company's larger competitors may have a competitive advantage when responding to factors that affect demand for oil and gas production, such as fluctuating worldwide commodity prices and levels of production, the cost and availability of alternative fuels, and the application of government regulations. The Company also competes in attracting and retaining personnel, including geologists, geophysicists, engineers, and other specialists. 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 11—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 by effectively increasing its future tax obligations.

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, 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. In addition, it is possible that the increasingly strict requirements imposed by environmental laws and enforcement policies could require the Company to make significant capital expenditures. Such capital expenditures could adversely impact the Company's cash flows and its financial condition.

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 such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls, and environmental protection laws and regulations.

In response to the Deepwater Horizon incident in the U.S. Gulf of Mexico in April 2010 and as directed by the Secretary of the U.S. Department of the Interior, the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) issued guidelines and regulations regarding safety, environmental matters, drilling equipment, and decommissioning applicable to drilling in the Gulf of Mexico. These regulations imposed additional requirements and caused delays with respect to development and production activities in the Gulf of Mexico.

With respect to oil and gas operations in the Gulf of Mexico, the 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 Apache provide additional security to BOEM with respect to plugging, abandonment, and decommissioning obligations relating to Apache'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 Apache has sold Gulf of Mexico assets or with whom Apache 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.

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 this sector 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.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit or restrict the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. Several states and political subdivisions are considering legislation, ballot initiatives, executive orders, or other actions to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. Hydraulic fracturing of wells and subsurface water disposal are also under public and governmental scrutiny due to potential environmental and physical impacts, including possible contamination of groundwater and drinking water and possible links to induced seismicity. In addition, some municipalities have significantly limited or prohibited drilling activities and/or hydraulic fracturing or are considering doing so. The Company routinely uses fracturing techniques in the U.S. and other regions to expand the available space for natural gas and oil to migrate toward the wellbore. It is typically done at substantial depths in formations with low permeability.

Although it is not possible at this time to predict the final outcome of the governmental actions regarding hydraulic fracturing, any new federal, state, or local restrictions on hydraulic fracturing that may be imposed in areas in which the Company conducts business could result in increased compliance costs or additional operating restrictions in the U.S.

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

The U.S. federal and state income tax laws affecting oil and gas exploration, development, and extraction may be modified by administrative, legislative, or judicial interpretation at any time. Previous legislative proposals, if enacted into law, could make significant changes to such 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, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) 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.

On May 26, 2022, the U.K. Chancellor of the Exchequer announced a new tax (the Energy Profits Levy) on the profits of oil and gas companies operating in the U.K. and the U.K. Continental Shelf. Under the new law, an additional levy is assessed at a 25 percent rate and is effective for the period of May 26, 2022, through December 31, 2025. On November 17, 2022, the U.K. Chancellor of the Exchequer announced in the Autumn Statement 2022 further changes to the Energy Profits Levy, increasing the levy assessed from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023, through March 31, 2028. On November 22, 2022, the U.K. Government published draft legislation to implement this change, among other provisions, and on January 10, 2023, the Finance Act 2023 was enacted, receiving Royal Assent. The impact of this tax could adversely affect the Company's future financial condition and cash flows.

On August 16, 2022, the U.S. enacted the Inflation Reduction Act of 2022 (IRA). Among other changes, the IRA introduced a new 15% 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. If the Company were to meet this average AFSI test, any resulting Corporate AMT liability could adversely affect the Company's future financial results, including earnings and cash flows.

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; technological advances with respect to the generation, transmission, storage, and consumption of alternative energy sources; and 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 the Company's, and in turn the prices it 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 legislation or regulation of GHGs, including to monitor and limit existing emissions of GHGs and to restrict or eliminate future emissions. Moreover, in January 2021, the

President issued an executive order that commits to substantial action on climate change, calling for, among other things, the elimination of subsidies provided to the fossil fuel industry and increased emphasis on climate-related risk across governmental agencies and economic sectors.

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 or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil, natural gas, and NGLs. Additionally, political, litigation, and financial risks related to climate change may result in curtailed refinery activity, increased regulation, or other adverse direct and indirect effects on the Company's business, financial condition, and results of operations. For example, there is a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Recently, the Federal Reserve announced that it has joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector.

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 the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits the Company requires to conduct its operations 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.

In 2021, the Company undertook a scenario planning analysis in alignment with recommendations of the Financial Stability Board's Taskforce on Climate-related Financial Disclosures (TCFD). This expanded climate-focused scenario planning framework included forecasts of future demand and pricing in energy markets, as well as changes in government regulations and policy. 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 TCFD 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 2040. Given the numerous estimates that are required to run these scenarios, the Company's estimates could differ materially from actual results. Additionally, by electing to set and share publicly these metrics in the Company's sustainability report and the Company's commitment to expand upon its disclosures, the Company's business may also face increased scrutiny related to ESG initiatives. As a result, the Company could damage its reputation if it fails to act responsibly in the areas in which it reports. Any harm to the Company's reputation resulting from setting these metrics, expanding its disclosures, or its failure or perceived failure to meet such metrics or disclosures could adversely affect the Company's business, financial performance, and growth.

The Company operates in Gulf Coast wetlands, which face threats from climate change and human activities.

A changing climate creates uncertainty and could result in broad changes, both physical and financial, to the areas in which the Company operates, including Gulf Coast wetlands. For several decades, the State of Louisiana has lost an estimated 20 square miles of wetlands per year, due to natural processes of subsidence, saltwater intrusion, and shoreline erosion, as well as human activities, such as levee construction along the Mississippi River and the dredging of navigation canals. A possible result of climate change is more frequent and more severe weather events, such as hurricanes and major flooding events. The risk of increased or more severe hurricanes or flooding events along or near the Gulf Coast could increase the Company's costs to repair damaged facilities and restore production. Additionally, federal, state, and local laws and regulations may impose numerous obligations applicable to the Company's operations, including: (i) the limitation or prohibition of certain activities on wetlands; (ii) the imposition of substantial liabilities for pollution resulting from operations; (iii) the reporting of the types and quantities of various substances that are generated, stored, processed, or released in connection with protected properties; and

(iv) the installation of costly emission monitoring and/or pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of the Company's operations. In addition, the Company may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt the Company's operations or specific projects and limit its growth and revenue.

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, and could expose the Company to financial risk.

Based on Ipieca's Sustainability Reporting Guidance of the Oil and Gas Industry (2020), the Company modified the way it reports its water data compared to previous years and also restated data from past 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. Produced water is generally not of the quality that most users would be able to utilize and is therefore not available for third-party usage outside of the oilfield. 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. The Company's ability to accurately report and track its water use is necessary for its continued ability to reuse and recycle water, when possible. 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 may increase the Company's operating costs, which could materially and adversely affect its business, results of operations, and financial conditions.

In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, the Railroad Commission of Texas (RRC) has been developing data associated with seismic activity, particularly such activity related to injection wells used for produced water disposal. In September 2021, the RRC began to limit saltwater disposal in the Midland Basin under what is known as a Seismic Response Action (or SAR) due to increased seismic activity.

Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the state to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. These developments could result in restriction of disposal wells that could have a material effect on the Company's capital expenses and operating costs or limit production in certain areas.

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. On a barrel equivalent basis, approximately 47 percent of the Company's 2022 production was outside the U.S., and approximately 32 percent of the Company's estimated proved oil and gas reserves as of December 31, 2022, 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:

- general strikes and civil unrest;

- the risk of war, acts of terrorism, expropriation and resource nationalization, and 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, including royalty and tax increases and retroactive tax claims, and investment restrictions;
- price control;
- transportation regulations and tariffs;
- constrained oil or natural gas markets dependent on demand in a single or limited geographical area;
- exchange controls, currency fluctuations, devaluations, or other activities that limit or disrupt markets and restrict payments or the movement of funds;
- laws and policies of the U.S. affecting foreign trade, including trade sanctions;
- the long-term effects of the U.K.'s withdrawal from the European Union, including any resulting instability in global financial markets or the value of foreign currencies such as the British pound;
- 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 deterioration of conditions in Egypt or changes in the economic and political environment in Egypt could have an adverse impact on the Company's business.

Deterioration in the political, economic, and social conditions or other relevant policies of the Egyptian government, such as changes in laws or regulations, export restrictions, 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, financial condition, and results of operations. The Company's operations in Egypt, excluding the impacts of noncontrolling interests, contributed 22 percent of the Company's 2022 production and accounted for 11 percent of the Company's year-end estimated proved reserves and 22 percent of the Company's estimated discounted future net cash flows.

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.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

Not applicable.

ITEM 3. *LEGAL PROCEEDINGS*

The information set forth under "Legal Matters" and "Environmental Matters" in Note 12—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*

Not applicable.

PART II

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

Apache is a wholly owned subsidiary of APA. Accordingly, all of Apache's common stock, par value $0.625 per share, is owned by APA, and there is no market for Apache's common stock.

ITEM 6. *SELECTED FINANCIAL DATA*

Omitted.

ITEM 7. *MANAGEMENT'S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS*

The following discussion relates to Apache Corporation (Apache 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 2022 and 2021 items and year-to-year comparisons between 2022 and 2021. Discussions of 2020 items and year-to-year comparisons between 2021 and 2020 that are not included in this Annual Report on Form 10-K are incorporated by reference to "Management's Narrative Analysis of 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, 2021 (filed with the SEC on February 22, 2022).

On March 1, 2021, Apache consummated a holding company reorganization (the Holding Company Reorganization), pursuant to which Apache became a direct, wholly owned subsidiary of APA Corporation (APA), and all of the Company's outstanding shares automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to the Company pursuant to Rule 12g-3(a) under the Exchange Act and replaced the Company as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized APA's operating and legal structure, making it more consistent with other companies that have affiliates operating around the globe. Refer to Note 2—Transactions with Parent Affiliate in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K for more detail.

Overview

Apache, a direct, wholly owned subsidiary of APA, is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids (NGLs). The Company's upstream business currently has exploration and production operations in three geographic areas: the U.S., Egypt, and offshore the U.K. in the North Sea (North Sea). Prior to the BCP Business Combination defined below, the Company's midstream business was operated by Altus. Altus owned, developed, and operated a midstream energy asset network in the Permian Basin of West Texas.

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

Early in 2020, impacts of the coronavirus disease 2019 (COVID-19) pandemic and related governmental actions began to exert significant downward pressure on crude oil and natural gas prices. Since that time, commodity prices worldwide have largely rebounded; however, uncertainties in the global supply chain, commodity prices, and financial markets, including the impact of inflation, rising interest rates, and the conflict in Ukraine continue to impact oil supply and demand. Despite these uncertainties, the Company remains committed to its longer-term objectives: (1) to maintain a balanced asset portfolio; (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.

During 2022, the Company reported net income of $3.5 billion compared to net income of $1.1 billion in 2021. Net income in 2022 benefited from higher commodity prices and increased revenues attributable to a new merged concession agreement in Egypt. The increase in realized prices was primarily driven by the effects of global inflation, the conflict in Ukraine on global commodity prices, and uncertainties around spare capacity and energy security globally.

The Company generated $4.9 billion of cash from operating activities in 2022, which was $1.3 billion, or 38 percent, higher than the prior year. Apache's higher operating cash flows for 2022 were driven by higher crude oil and natural gas prices and associated revenues. Since year-end 2021, the Company has reduced its total outstanding debt and redeemable preferred interests by $2.6 billion and $712 million, respectively, through the deconsolidation of ALTM and the retirement of outstanding notes and debentures.

Operational Highlights

Key operational highlights for the year include:

United States

- Daily boe production from the Company's U.S. assets, which decreased 12 percent from the prior year end, accounted for 52 percent of its total worldwide production during 2022. During 2022, the Company averaged 4 drilling rigs in the U.S., averaging 2 rigs each in the Southern Midland Basin and Delaware Basin assets. The Company's core Midland Basin development program is expected to represent key growth areas for the U.S. assets.

International

- In December 2021, the Egyptian President signed and ratified the previously announced agreement with the Egyptian Ministry of Petroleum and the Egyptian General Petroleum Corporation (EGPC) to modernize the terms of the majority of the Company's production-sharing contracts, having an effective date of April 1, 2021. The new merged concession agreement (MCA) consolidated 98 percent of gross acreage and 90 percent of gross production under one concession agreement and refreshes the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool that provides 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 new concession. The changes also simplify the contractual relationship with EGPC, facilitate recovery of prior investment, and update day-to-day operational governance. Sinopec International Petroleum Exploration and Production Corporation (Sinopec) owns a one-third minority participation in the Company's consolidated Egypt oil and gas business, and a portion of the remaining net income and distributable cash flow is allocated to APA in accordance with the terms of the agreement.
- Egypt gross equivalent production decreased 1 percent and net production increased 26 percent from 2021, primarily a function of improved cost recovery under the new merged concession agreement ratified at the end of 2021. 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. The Company continues to increase drilling and workover activity as a result of the merged concession agreement. Egypt production growth is building on improvements in new well connections and recompletion activity.
- During 2022, the Company focused on several environmental initiatives in Egypt and has delivered on its 2022 upstream flaring reduction goal by flaring at least 40 percent less gas than would otherwise be flared without these initiatives, with the Company now compressing this gas into sales lines.
- The North Sea maintained two drilling rigs during 2022. Production was negatively impacted by considerable planned and unplanned downtime at Beryl and Forties during the third quarter of 2022, improving in the fourth quarter of 2022 following completion of these maintenance activities.

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 Apache'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 during 2022 include:

- *BCP Business Combination* 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). Upon closing the transaction, the combined entity was renamed Kinetik Holdings Inc. (Kinetik). 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.

  ALTM's stockholders continued to hold their existing 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. The Company deconsolidated ALTM upon closing the transaction and recognized a gain of approximately $609 million that reflects the difference of the Company's share of ALTM's deconsolidated balance sheet and the fair value of its 20 percent retained ownership in the combined entity.

  Subsequent to the close of the transaction, in March 2022, the Company sold four million of its shares of Kinetik Class A Common Stock for $224 million, reducing the Company's retained ownership percentage in Kinetik to approximately 13 percent.

- *Delaware Basin Divestitures* During 2022, the Company completed a previously announced transaction to sell certain non-core mineral rights in the Delaware Basin, for total cash proceeds of $726 million.

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

- *U.S. Leasehold Divestitures & Other* During 2022, the Company completed the sale of non-core assets and leasehold in multiple transactions for total cash proceeds of $52 million.

For detailed information regarding Apache's acquisitions and divestitures, refer to Note 3—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,					
	2022		2021		2020	
	$ Value	% Contribution	$ Value	% Contribution	$ Value	% Contribution
	($ in millions)					
Oil Revenues:						
United States	$ 2,323	35 %	$ 1,850	40 %	$ 1,209	39 %
Egypt[(1)]	3,145	47 %	1,806	40 %	1,102	35 %
North Sea	1,232	18 %	929	20 %	795	26 %
Total[(1)]	$ 6,700	100 %	$ 4,585	100 %	$ 3,106	100 %
Natural Gas Revenues:						
United States	$ 894	58 %	$ 754	62 %	$ 251	42 %
Egypt[(1)]	370	24 %	270	23 %	280	47 %
North Sea	281	18 %	183	15 %	67	11 %
Total[(1)]	$ 1,545	100 %	$ 1,207	100 %	$ 598	100 %
NGL Revenues:						
United States	$ 732	93 %	$ 673	95 %	$ 304	91 %
Egypt[(1)]	6	1 %	9	1 %	8	3 %
North Sea	45	6 %	24	4 %	21	6 %
Total[(1)]	$ 783	100 %	$ 706	100 %	$ 333	100 %
Oil and Gas Revenues:						
United States	$ 3,949	44 %	$ 3,277	50 %	$ 1,764	44 %
Egypt[(1)]	3,521	39 %	2,085	32 %	1,390	34 %
North Sea	1,558	17 %	1,136	18 %	883	22 %
Total[(1)]	$ 9,028	100 %	$ 6,498	100 %	$ 4,037	100 %

(1) Includes revenues attributable to noncontrolling interests in Egypt.

Production

The following table presents production volumes by country:

	For the Year Ended December 31,				
	2022	Increase (Decrease)	2021	Increase (Decrease)	2020
Oil Volumes – b/d:					
United States[5]	66,142	(12)%	75,205	(15)%	88,249
Egypt[3][4]	85,081	21%	70,349	(7)%	75,384
North Sea	32,578	(10)%	36,265	(28)%	50,386
Total	183,801	1%	181,819	(15)%	214,019
Natural Gas Volumes – Mcf/d:					
United States[5]	459,123	(13)%	527,461	(6)%	561,731
Egypt[3][4]	356,327	35%	263,653	(4)%	274,175
North Sea	35,327	(8)%	38,565	(33)%	57,464
Total	850,777	3%	829,679	(7)%	893,370
NGL Volumes – b/d:					
United States[5]	59,887	(10)%	66,232	(11)%	74,136
Egypt[3][4]	196	(63)%	531	(30)%	754
North Sea	1,111	(7)%	1,199	(38)%	1,936
Total	61,194	(10)%	67,962	(12)%	76,826
BOE per day:[1]					
United States[5]	202,549	(12)%	229,348	(10)%	256,007
Egypt[3][4]	144,665	26%	114,821	(6)%	121,834
North Sea[2]	39,577	(10)%	43,892	(29)%	61,899
Total	386,791	—%	388,061	(12)%	439,740

(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 40,812 boe/d, 44,179 boe/d, and 62,157 boe/d for 2022, 2021, and 2020, respectively. Sales volumes may vary from production volumes as a result of the timing of liftings in the Beryl field.

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

	2022	2021	2020
Oil (b/d)	137,260	134,711	164,104
Natural Gas (Mcf/d)	555,562	586,663	641,069
NGL (b/d)	297	854	1,429

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

	2022	2021	2020
Oil (b/d)	45,216	23,504	25,206
Natural Gas (Mcf/d)	189,339	88,409	91,540
NGL (b/d)	104	177	251

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

	2022	2021	2020
Oil (b/d)	777	1,485	2,718
Natural Gas (Mcf/d)	192,253	258,096	274,279
NGL (b/d)	18,362	22,950	24,942

Pricing

The following table presents pricing information by country:

	For the Year Ended December 31,							
		2022	Increase (Decrease)		2021	Increase (Decrease)		2020
Average Oil Price - Per barrel:								
United States	$	96.25	43%	$	67.37	80%	$	37.42
Egypt		101.25	44%		70.33	76%		39.95
North Sea		100.87	45%		69.67	62%		42.88
Total		99.39	44%		68.97	74%		39.60
Average Natural Gas Price - Per Mcf:								
United States	$	5.33	36%	$	3.92	221%	$	1.22
Egypt		2.85	1%		2.81	1%		2.79
North Sea		23.36	80%		12.96	306%		3.19
Total		4.97	25%		3.99	118%		1.83
Average NGL Price - Per barrel:								
United States	$	33.47	20%	$	27.85	148%	$	11.21
Egypt		76.80	57%		48.84	75%		27.83
North Sea		67.07	24%		54.30	83%		29.73
Total		34.62	22%		28.48	141%		11.84

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 2022 were up 44 percent compared to 2021, a direct result of the rising benchmark oil prices over the past year. Crude oil prices realized in 2022 averaged $99.39 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. Price movements 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 $5.33 per Mcf in 2022, a 36 percent increase from an average of $3.92 per Mcf in 2021.
- 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 $2.85 per Mcf in 2022, a 1 percent increase from an average of $2.81 per Mcf in 2021.
- 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 $23.36 per Mcf in 2022, an 80 percent increase from an average of $12.96 per Mcf in 2021.

NGL Prices The Company's U.S. NGL production, which accounted for 98 percent of the Company's total 2022 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 2022 totaled $6.7 billion, a $2.1 billion increase from the 2021 total of $4.6 billion. A 44 percent increase in average realized prices increased 2022 revenues by $2.0 billion compared to 2021, while 1 percent higher average daily production increased revenues by $98 million. Average daily production in 2022 was 184 Mb/d, with prices averaging $99.39 per barrel. Crude oil sales accounted for 74 percent of the Company's 2022 oil and gas production revenues and 48 percent of its worldwide production.

The Company's worldwide crude oil production increased 2 Mb/d compared to 2021, primarily a function of improved cost recovery under the merged concession agreement in Egypt ratified at the end of 2021, offset by extended operational downtime in the North Sea and natural production decline across all assets.

Natural Gas Revenues

Natural gas revenues for 2022 totaled $1.5 billion, a $338 million increase from the 2021 total of $1.2 billion. A 25 percent increase in average realized prices increased 2022 revenues by $303 million compared to 2021, while 3 percent higher average daily production increased revenues by $35 million. Average daily production in 2022 was 851 MMcf/d, with prices averaging $4.97 per Mcf. Natural gas sales accounted for 17 percent of the Company's 2022 oil and gas production revenues and 36 percent of its worldwide production.

The Company's worldwide natural gas production increased 21 MMcf/d compared to 2021, primarily a result of increased net production in Egypt resulting from improved cost recovery under the merged concession agreement ratified at the end of 2021, offset by extended operational downtime in the North Sea and natural production decline across all assets.

NGL Revenues

NGL revenues for 2022 totaled $783 million, a $77 million increase from the 2021 total of $706 million. A 22 percent increase in average realized prices increased 2022 revenues by $152 million compared to 2021, while 10 percent lower average daily production decreased revenues by $75 million. Average daily production in 2022 was 61 Mb/d, with prices averaging $34.62 per barrel. NGL sales accounted for 9 percent of the Company's 2022 oil and gas production revenues and 16 percent of its worldwide production.

The Company's worldwide NGL production decreased 7 Mb/d compared to 2021, primarily a result of natural production decline in the U.S.

Altus Midstream Revenues

Prior to the deconsolidation of Altus on February 22, 2022, the Company beneficially owned approximately 79 percent of ALTM's outstanding voting common stock. Altus owned and operated a midstream energy asset network in the Permian Basin of West Texas primarily to service the Company's production from its Alpine High resource play, which commenced production in May 2017.

Altus Midstream primarily generated revenue by providing fee-based natural gas gathering, compression, processing, and transmission services. For the years ended December 31, 2022 and 2021, Altus Midstream's service revenues generated through its fee-based contractual arrangements with the Company totaled $16 million and $127 million, respectively. These affiliated revenues were eliminated upon consolidation.

Purchased Oil and Gas Sales

Purchased oil and gas sales represent volumes primarily attributable to transport, fuel, and physical in-basin gas purchases that were sold by the Company to fulfill natural gas takeaway obligations. Sales related to these purchased volumes increased $368 million for the year ended December 31, 2022 to $1.9 billion from $1.5 billion in the prior year. Purchased oil and gas sales were offset by associated purchase costs of $1.8 billion and $1.6 billion for the years ended December 31, 2022 and 2021, respectively. The increase is a result of higher average natural gas prices during 2022 compared to the prior year.

Operating Expenses

The table below presents a comparison of the Company's operating expenses for the years ended December 31, 2022, 2021, and 2020. All operating expenses include costs attributable to a noncontrolling interest in Egypt and Altus.

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Lease operating expenses	$ 1,435	$ 1,241	$ 1,127
Gathering, processing, and transmission	356	264	274
Purchased oil and gas costs	1,776	1,580	357
Taxes other than income	256	204	123
Exploration	146	127	274
General and administrative	462	357	290
Transaction, reorganization, and separation	26	22	54
Depreciation, depletion, and amortization:			
Oil and gas property and equipment	1,130	1,255	1,643
Gathering, processing, and transmission assets	15	64	76
Other assets	32	41	53
Asset retirement obligation accretion	117	113	109
Impairments	—	208	4,501
Financing costs, net	313	472	267

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 48 percent of the Company's total 2022 production, is inherently more expensive to produce than natural gas. Repair and maintenance costs are typically higher on offshore properties.

During 2022, LOE increased $194 million, or 16 percent, compared to 2021. On a per-boe basis, LOE increased $1.14, or 13 percent, compared to 2021, from $8.75 per boe to $9.89 per boe. The increase in costs was driven by higher labor costs and operating costs trending with higher oil and gas prices and global inflation, coupled with higher workover activity in the U.S. during 2022.

Gathering, Processing, and Transmission (GPT)

GPT expenses include amounts paid to third-party carriers and to Altus Midstream for gathering and transmission services for the Company's upstream natural gas production associated with its Alpine High play. GPT expenses also include midstream operating costs incurred by Altus Midstream. The following table presents a summary of these expenses:

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Third-party processing and transmission costs	$ 260	$ 232	$ 236
Midstream service costs - ALTM	18	128	143
Midstream service costs - Kinetik	91	—	—
Upstream processing and transmission costs	369	360	379
Midstream operating expenses	5	32	38
Intersegment eliminations	(18)	(128)	(143)
Total Gathering, processing, and transmission	$ 356	$ 264	$ 274

GPT costs increased $92 million compared to 2021. Third-party processing and transmission costs increased $28 million, primarily driven by an increase in average transportation rates during the year. Costs for services provided by ALTM in the first quarter of 2022 and 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 BCP Business Combination and the Company's deconsolidation of Altus on February 22, 2022, these midstream services continue to be provided by Kinetik but are no longer eliminated. Midstream services provided by Kinetik totaled $91 million for the year ended 2022.

Purchased Oil and Gas Costs

Purchased oil and gas costs increased $196 million compared to 2021, and were primarily offset by associated sales totaling $1.9 billion for the year ended 2022, as discussed above.

Taxes Other Than Income

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

Taxes other than income increased $52 million compared to 2021, primarily from higher severance taxes driven by higher commodity prices.

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,		
	2022	2021	2020
		(In millions)	
Unproved leasehold impairments	$ 24	$ 31	$ 101
Dry hole expenses	69	55	110
Geological and geophysical expenses	6	8	20
Exploration overhead and other	47	33	43
Total Exploration	$ 146	$ 127	$ 274

Exploration expenses increased $19 million compared to 2021, primarily the result of higher dry hole expenses in Egypt and higher exploration overhead, a function of increased exploration activities.

General and Administrative (G&A) Expenses

G&A expenses increased $105 million compared to 2021, primarily driven by higher cash-based stock compensation expense resulting from an increase in the Company's stock price and achievement of performance and financial objectives as defined in the stock award plans. Higher overall wages across the Company and global inflationary pressures also impacted G&A expenses compared to the prior-year period.

Transaction, Reorganization, and Separation (TRS) Costs

TRS costs increased $4 million compared to 2021, primarily a result of transaction costs from the BCP Business Combination, partially offset by a decrease in costs associated with the Company's prior year reorganization efforts that are substantially completed.

Depreciation, Depletion and Amortization (DD&A)

DD&A expenses on the Company's oil and gas property for the year ended December 31, 2022 decreased $125 million compared to 2021. The Company's oil and gas property DD&A rate decreased $1.06 per boe in 2022 compared to 2021, from $8.85 per boe to $7.79 per boe. The decrease on an absolute basis was driven by lower depletion rates in Egypt under the new merged concession agreement, partially offset by higher production volumes. DD&A expense on the Company's GPT depreciation decreased $49 million compared to 2021, primarily driven by certain Egyptian assets being fully depreciated coupled with the deconsolidation of Altus during the first quarter of 2022.

Impairments

No asset impairments were recorded in 2022. During 2021, the Company recorded asset impairments totaling $208 million. The charges include $160 million for Altus' equity method interests, $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.

During 2020, the Company recorded asset impairments in connection with fair value assessments totaling $4.5 billion, including $4.3 billion for oil and gas proved properties in the U.S, Egypt, and the North Sea, $68 million for GPT facilities in Egypt, $87 million for goodwill in Egypt, and $27 million for inventory and other miscellaneous assets.

The following table presents a summary of asset impairments recorded for 2022, 2021, and 2020:

	For the Year Ended December 31,		
	2022	**2021**	**2020**
		(In millions)	
Oil and gas proved property	$ —	$ —	$ 4,319
GPT facilities	—	—	68
Equity method interests	—	160	—
Goodwill	—	—	87
Inventory and other	—	48	27
Total Impairments	$ —	$ 208	$ 4,501

Financing Costs, Net

Financing costs incurred during 2022, 2021, and 2020 comprised the following:

	For the Year Ended December 31,		
	2022	**2021**	**2020**
		(In millions)	
Interest expense	$ 312	$ 419	$ 438
Amortization of debt issuance costs	7	8	8
Capitalized interest	(1)	—	(12)
Loss (gain) on extinguishment of debt	67	104	(160)
Interest income	(9)	(8)	(7)
Interest income from APA Corporation, net	(63)	(51)	—
Total Financing costs, net	$ 313	$ 472	$ 267

Net financing costs during 2022 decreased $159 million compared to 2021, primarily the result of the reduction of fixed-rate debt during 2021 and the first half of 2022. Additionally, losses incurred on the extinguishment of debt were lower during 2022 compared to the prior year period.

Provision for Income Taxes

Income tax expense increased $1.1 billion from $578 million during 2021 to $1.7 billion during 2022. The Company's year-to-date 2022 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 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. During 2021, the Company's effective income tax rate was primarily impacted by asset impairments and a decrease in the amount of valuation allowance against its U.S. deferred tax assets.

On May 26, 2022, the U.K. Chancellor of the Exchequer announced a new tax (the Energy Profits Levy) on the profits of oil and gas companies operating in the U.K. and the U.K. Continental Shelf. Under the new law, an additional levy is assessed at a 25 percent rate and is effective for the period of May 26, 2022, through December 31, 2025. The Company recorded a deferred tax expense of $208 million associated with the remeasurement of the U.K. deferred tax liability. On November 17, 2022, the U.K. Chancellor of the Exchequer announced in the Autumn Statement 2022 further changes to the Energy Profits Levy, increasing the levy assessed from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023, through March 31, 2028. On November 22, 2022, the U.K. Government published draft legislation to implement this change, among other provisions, and on January 10, 2023, the Finance Act 2023 was enacted, receiving Royal Assent. Under U.S. GAAP, the financial statement impact of new legislation is recorded in the period of enactment. Therefore, in the first quarter of 2023, the Company expects to record a deferred tax expense of approximately $170 million to $190 million related to the remeasurement of the December 31, 2022 U.K. deferred tax liability.

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 (Corporate AMT) 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 Corporate AMT is effective for tax years beginning after December 31, 2022. The Company is continuing to evaluate the provisions of the IRA and awaits further guidance from the U.S. Treasury Department to properly assess the impact of these provisions on the Company.

The Company recorded a full valuation allowance against its U.S. net deferred tax assets. 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. A significant piece of negative evidence evaluated was the U.S. pre-tax book cumulative loss incurred over the three-year period ended December 31, 2022. This cumulative loss was primarily the result of low commodity prices and oil and gas impairments during this period. Such objective evidence limits the ability to consider other subjective evidence, such as the Company's projections for future growth.

However, given the Company's current and anticipated future domestic earnings, the Company believes that there is a reasonable possibility that within the next 12 months the U.S. will exit its cumulative loss, allowing the Company to reach a conclusion that a material portion of the U.S. valuation allowance may no longer be needed. A release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense, which could be material for the period the release is recorded. For additional information regarding income taxes, refer to Note 11—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 state and foreign jurisdictions. The Company's tax reserves are related to tax years that may be subject to examination by the relevant taxing authority. The Company is currently under audit by the Internal Revenue Service (IRS) for the 2014-2017 tax years and is also under audit in various states and foreign jurisdictions as part of its normal course of business.

Potential Decommissioning Obligations on Sold Properties

The Company has potential exposure to future obligations related to divested properties. Apache 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, Apache could be required to perform such actions under applicable federal laws and regulations. In such event, Apache 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. Currently, Apache holds two bonds (Bonds) and five Letters of Credit backed by investment-grade counterparties to secure 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 decommissioning of Legacy GOM Assets.

By letter dated April 5, 2022, replacing two prior letters dated September 8, 2021 and February 22, 2022, 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 notification to BSEE. Apache expects to receive such orders on the other Legacy GOM Assets included in GOM Shelf's notification letter. 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.

If Apache incurs costs to decommission any Legacy GOM Asset and GOM Shelf does not reimburse Apache for such costs, then Apache expects to obtain reimbursement from Trust A, the Bonds, and the Letters of Credit until 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 ordered by BSEE to perform, 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 effectively use its available cash to fund the deficit.

As of December 31, 2022, Apache estimates that its potential liability to fund decommissioning of Legacy GOM Assets it may be ordered to perform ranges from $1.2 billion to $1.4 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 $1.2 billion as of December 31, 2022, representing the estimated costs of decommissioning it may be required to perform on Legacy GOM Assets. Of the total liability recorded, $738 million is reflected under the caption "Decommissioning contingency for sold Gulf of Mexico properties," and $450 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, 2022, the Company has also recorded a $667 million asset, which represents the 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, $217 million is reflected under the caption "Decommissioning security for sold Gulf of Mexico properties," and $450 million is reflected under "Other current assets." The Company recognized $157 million and $446 million during 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.

Insurance Program

The Company is covered by insurance 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, such 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 is covered by a 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.

The Company 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 the Company on past due invoices and (2) expropriation of exportable petroleum in the event that actions taken by the government of Egypt prevent the Company 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.

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.

Despite significant 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 19—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 potential decommissioning obligations on sold properties estimated and recorded in the third quarter of 2021, please refer to “Potential Decommissioning Obligation on Sold Properties” above and in Note 12—Commitments and Contingencies in the Notes to Consolidated Financial Statements in Part IV, Item 5 of this Annual Report on Form 10-K. Changes in significant assumptions impacting the Company’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.

Impairment of 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.

Altus recorded an impairment charge on its equity method interest in the EPIC crude oil pipeline (EPIC) in the fourth quarter of 2021. The fair value of the impaired interest was determined using the income approach. The income approach considered estimates of future throughput volumes, tariff rates, and costs. These assumptions were applied to develop future cash flow projections that were then discounted to estimated fair value, using a discount rate believed to be consistent with that which would be applied by market participants. The Company has classified this nonrecurring fair value measurement as Level 3 in the fair value hierarchy. Refer to Note 7—Equity Method Interests, within Part IV, Item 15 of this Annual Report on Form 10-K for further details of Altus’ equity method interests.

Long-Lived Asset Impairments

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

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

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

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

Over the past several years, the Company has experienced substantial volatility in commodity prices, which impacted its future development plans and operating cash flows. As such, material impairments of certain proved oil and gas properties and gathering, processing, and transmission facilities were recorded in 2020. For discussion of these impairments, see "Fair Value Measurements" of Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

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 and Gulf of Mexico. 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).

The Company regularly assesses and, if required, establishes accruals for uncertain tax positions that could result from assessments of additional tax by taxing jurisdictions in countries where the Company operates. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. These accruals for uncertain tax positions are subject to a significant amount of judgment and are reviewed and adjusted on a periodic basis in light of changing facts and circumstances considering the progress of ongoing tax audits, case law, and any new legislation. The Company believes that its accruals for uncertain tax positions are adequate in relation to the potential for any additional tax assessments.

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, global inflation, and other current events.

The Company's average crude oil price realizations increased 44 percent to $99.39 per barrel in 2022 from $68.97 per barrel in 2021. The Company's average natural gas price realizations increased 25 percent to $4.97 per Mcf in 2022 from $3.99 per Mcf in 2021. The Company's average NGL price realizations increased 22 percent to $34.62 per barrel in 2022 from $28.48 per barrel in 2021. Based on average daily production for 2022, a $1.00 per barrel change in the weighted average realized oil price would have increased or decreased revenues for the year by approximately $67 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 $31 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 $22 million.

Interest Rate Risk

At December 31, 2022, Apache had $4.9 billion, net, in outstanding notes and debentures, all of which was fixed-rate debt, with a weighted average interest rate of 5.32 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, 2022, the Company had approximately $185 million in cash and cash equivalents, approximately 80 percent of which was invested in money market funds and short-term investments with major financial institutions. As of December 31, 2022, Apache had no borrowings outstanding under APA's syndicated revolving credit facilities. A change in the interest rate applicable to short-term investments and credit facility borrowings would 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.

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. A 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, 2022.

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-62 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, 2022, 2021, and 2020, 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 and President, in his capacity as principal executive officer, and Stephen J. Riney, the Company's Executive Vice President and Chief Financial Officer, in his capacity as principal financial officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of December 31, 2022, 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

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.

This Annual Report on Form 10-K does not include an attestation report of the Company's independent registered public accounting firm on the Company's internal control over financial reporting. As a non-accelerated filer, the management report called for by Item 308(a) of Regulation S-K is not subject to attestation by the Company's independent registered public accounting firm.

Changes in Internal Control over Financial Reporting

There was no change in our internal controls over financial reporting during the quarter ending December 31, 2022, that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 9B. *OTHER INFORMATION*

None.

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

Not applicable.

PART III

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

This section has been omitted pursuant to General Instruction I(2)(c) of Form 10-K.

ITEM 11. ***EXECUTIVE COMPENSATION***

This section has been omitted pursuant to General Instruction I(2)(c) of Form 10-K.

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

This section has been omitted pursuant to General Instruction I(2)(c) of Form 10-K.

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

This section has been omitted pursuant to General Instruction I(2)(c) of Form 10-K.

ITEM 14. ***PRINCIPAL ACCOUNTING FEES AND SERVICES***

Accountant fees and services paid to Ernst & Young LLP, the Company's independent auditors, are included in amounts paid by APA on behalf of Apache. Information on APA's principal accountant fees and services is set forth under the caption "Ratification of Appointment of Independent Auditors" in the APA Proxy Statement 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
2.1	–	Agreement and Plan of Merger, dated as of March 1, 2021, by and among Registrant, APA Corporation, and APA Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Registrant's Current Report on Form 8-K filed March 1, 2021, SEC File No. 001-4300).
3.1	–	Amended and Restated Certificate of Incorporation of Registrant, dated March 1, 2021, as attached as Annex A to the Certificate of Merger of APA Merger Sub, Inc. with and into Registrant, filed with the Secretary of State of the State of Delaware on March 1, 2021 (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed March 1, 2021, SEC File No. 001-4300).
3.2	–	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Registrant, dated June 7, 2021, filed with the Secretary of State of the State of Delaware on June 10, 2021 (incorporated by reference to Exhibit 3.1 to Registrant's Current Report on Form 8-K filed June 14, 2021, SEC File No. 001-4300).
3.3	–	Amended and Restated Bylaws of Registrant, dated March 1, 2021 (incorporated by reference to Exhibit 3.2 to Registrant's Current Report on Form 8-K filed March 1, 2021, SEC File No. 001-4300).
4.1	–	Form of Certificate for Registrant's Common Stock (incorporated by reference to Exhibit 4.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, SEC File No. 001-4300).
4.2	–	Form of 7.70% Notes due 2026 (incorporated by referenced to Exhibit 4.1 to Registrant's Current Report on Form 8-K, filed on February 23, 1996, SEC File No. 001-4300).
4.3	–	Form of 7.95% Notes due 2026 (incorporated by referenced to Exhibit 4.1 to Registrant's Current Report on Form 8-K, filed on April 23, 1996, SEC File No. 001-4300).
4.4	–	Form of 7.625% Debentures due 2096 (incorporated by referenced to Exhibit 4.2 to Registrant's Current Report on Form 8-K, filed on November 4, 1996, SEC File No. 001-4300).
4.5	–	Form of 7.375% Debentures due 2047 (incorporated by referenced to Exhibit 4.1 to Registrant's Current Report on Form 8-K, filed on August 8, 1997, SEC File No. 001-4300).
4.6	–	Form of 6.000% Notes due 2037 (incorporated by referenced to Exhibit 4.2 to Registrant's Current Report on Form 8-K, filed on January 26, 2007, SEC File No. 001-4300).
4.7	–	Form of 5.250% Notes due 2042 (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K, dated November 30, 2010, filed on December 3, 2010, SEC File No. 001-4300).
4.8	–	Form of 5.100% Notes due 2040 (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K, dated August 17, 2010, filed on August 20, 2010, SEC File No. 001-4300).
4.9	–	Form of 4.75% Notes due 2043 (incorporated by reference to Exhibit 4.3 to Registrant's Current Report on Form 8-K, dated April 3, 2012, filed on April 9, 2012, SEC File No. 001-4300).
4.10	–	Form of 4.250% Notes due 2044 (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K, dated November 28, 2012, filed on December 4, 2012, SEC File No. 001-4300).
4.11	–	Form of 4.375% Notes due 2028 (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K, filed on August 16, 2018, SEC File No. 001-4300).
4.12	–	Form of 4.250% Notes due 2030 (incorporated by referenced to Exhibit 4.1 to Registrant's Current Report on Form 8-K, filed on June 10, 2019, SEC File No. 001-4300).
4.13	–	Form of 5.350% Notes due 2049 (incorporated by referenced to Exhibit 4.2 to Registrant's Current Report on Form 8-K, filed on June 10, 2019, SEC File No. 001-4300).
4.14	–	Form of 4.625% Notes due 2025 (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K, filed on August 6, 2020, SEC File No. 001-4300).
4.15	–	Form of 4.875% Notes due 2027 (incorporated by reference to Exhibit 4.2 to Registrant's Current Report on Form 8-K, filed on August 6, 2020, SEC File No. 001-4300).
4.16	–	Form of 7.75% Notes due December 15, 2029 (incorporated by reference to Exhibit 4.1 to Registrant's Current Report on Form 8-K/A, filed on December 14, 1999, SEC File No. 001-4300).
4.17	–	Senior Indenture, dated February 15, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.6 to Registrant's Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).
4.18	–	First Supplemental Indenture to the Senior Indenture, dated as of November 5, 1996, between Registrant and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as trustee, governing the senior debt securities and guarantees (incorporated by reference to Exhibit 4.7 to Registrant's Registration Statement on Form S-3, dated May 23, 2003, Reg. No. 333-105536).

EXHIBIT NO.		DESCRIPTION
4.19	–	Second Supplemental Indenture, dated as of December 16, 2019, among Apache Corporation and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank, N.A., formerly The Chase Manhattan Bank, formerly Chemical Bank), as trustee under Indenture, dated as of February 15, 1996, as previously amended and supplemented (incorporated by reference to Exhibit 4.15 to Registrant's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
4.20	–	Form of Indenture among Registrant, Apache Finance Canada Corporation and The Bank of New York Mellon Trust Company, N.A. (formerly known as the Bank of New York Trust Company, N.A., as successor-in-interest to The Chase Manhattan Bank), as trustee, governing the debt securities and guarantees (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to Registrant's Registration Statement on Form S-3, dated November 12, 1999, Reg. No. 333-90147).
4.21	–	Supplemental Indenture, dated as of August 14, 2017, among Apache Finance Canada Corporation, Apache Corporation, and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank, N.A., formerly The Chase Manhattan Bank), as trustee (incorporated by reference to Exhibit 4.1 to Registrant's Quarterly Report on Form 10-Q filed November 3, 2017, SEC File No. 001-04300).
4.22	–	Second Supplemental Indenture, dated as of December 16, 2019, among Apache Corporation (as successor to Apache Finance Canada Corporation) and The Bank of New York Mellon Trust Company, N.A. (as successor to JPMorgan Chase Bank, N.A., formerly The Chase Manhattan Bank), as trustee under Indenture, dated as of November 23, 1999, as previously amended and supplemented (incorporated by reference to Exhibit 4.18 to Registrant's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
4.23	–	Senior Indenture, dated May 19, 2011, between Registrant and Wells Fargo Bank, National Association, as trustee, governing the senior debt securities of Apache Corporation (incorporated by reference to Exhibit 4.14 to Registrant's Registration Statement on Form S-3, dated May 23, 2011, Reg. No. 333-174429).
4.24	–	Supplemental Indenture, dated as of December 16, 2019, among Apache Corporation and Wells Fargo Bank, National Association, as trustee under Indenture, dated as of May 19, 2011 (incorporated by reference to Exhibit 4.20 to Registrant's Annual Report on Form 10-K for year ended December 31, 2019, SEC File No. 001-4300).
4.25	–	Indenture, dated August 14, 2018, by and between Apache Corporation and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to Registrant's Post-Effective Amendment No. 1 to Registration Statement on Form S-3 filed August 14, 2018, SEC File No. 333-219345).
10.1	–	Guaranty [USD Facility], dated as of April 29, 2022, made by Apache Corporation in favor of each of the lenders, issuing banks, and agents party to the Credit Agreement, 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 (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed May 2, 2022, SEC File No. 001-4300).
10.2	–	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, Bank of America, N.A., as Syndication Agent, Royal Bank of Canada, HSBC Bank USA, National Association, MUFG Bank, Ltd., Wells Fargo Bank, National Association, Goldman Sachs Bank USA, The Toronto-Dominion Bank, New York Branch, The Bank of Nova Scotia, Houston Branch, Truist Bank, and Mizuho Bank, Ltd., as Co-Documentation Agents (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed May 2, 2022, SEC File No. 001-4300).
10.3	–	Guaranty [GBP Facility], dated as of April 29, 2022, made by Apache Corporation in favor of each of the lenders, issuing banks, and agents party to the Credit Agreement, 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 (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed May 2, 2022, SEC File No. 001-4300).
10.4	–	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, The Toronto-Dominion Bank, London Branch, as Syndication Agent, Bank of America, N.A., Royal Bank of Canada, HSBC Bank USA, National Association, MUFG Bank, Ltd., Wells Fargo Bank, N.A. London Branch, Goldman Sachs Bank USA, The Bank of Nova Scotia, Houston Branch, Truist Bank, and Mizuho Bank, Ltd., as Co-Documentation Agents (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed May 2, 2022, SEC File No. 001-4300).
†10.5	–	Non-Qualified Retirement/Savings Plan of Apache Corporation, as amended and restated, dated July 16, 2014, effective January 1, 2015 (incorporated by reference to Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, SEC File No. 001-4300).
†10.6	–	Amendment to Non-Qualified Retirement/Savings Plan of Apache Corporation, dated August 12, 2020, effective August 1, 2020 (incorporated by reference to Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020, SEC File No. 001-4300).

EXHIBIT NO.		DESCRIPTION
†10.7	–	Amendment to Apache Corporation Non-Qualified Retirement/Savings Plan, dated March 1, 2021 (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed March 1, 2021, SEC File No. 001-4300).
†10.8	–	Non-Qualified Restorative Retirement Savings Plan of Apache Corporation, as amended and restated, dated July 16, 2014, effective January 1, 2015 (incorporated by reference to Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, SEC File No. 001-4300).
†10.9	–	Amendment to Apache Corporation Non-Qualified Restorative Retirement Savings Plan, dated March 1, 2021 (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed March 1, 2021, SEC File No. 001-4300).
*23.1	–	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.
*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.

† 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.

APACHE CORPORATION

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

Dated: February 23, 2023

POWER OF ATTORNEY

The officers and directors of Apache 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, Chief Executive Officer, and President (principal executive officer)	February 23, 2023
/s/ Stephen J. Riney Stephen J. Riney	Executive Vice President and Chief Financial Officer (principal financial officer)	February 23, 2023
/s/ Rebecca A. Hoyt Rebecca A. Hoyt	Senior Vice President, Chief Accounting Officer, and Controller (principal accounting officer)	February 23, 2023
/s/ Clay Bretches Clay Bretches	Director and Executive Vice President, Operations	February 23, 2023
/s/ David A. Pursell David A. Pursell	Director and Executive Vice President, Development	February 23, 2023
/s/ Mark D. Maddox Mark D. Maddox	Director and Executive Vice President, Administration	February 23, 2023

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, 2022. 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, 2022.

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 Apache 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 and President
(principal executive officer)

/s/ Stephen J. Riney
Executive Vice 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 23, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and the Board of Directors of Apache Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Apache Corporation and subsidiaries (the Company) as of December 31, 2022 and 2021, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

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 Public Company Accounting Oversight Board (United States) (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

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, 2022, the carrying value of the Company's property and equipment was $7,957 million, and depreciation, depletion and amortization (DD&A) expense was $1,177 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. Significant judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data 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, 2022.

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. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's development plan and the availability of capital relative to the development plan. 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, 2022, the asset retirement obligation (ARO) balance totaled $1,991 million. As further described in Note 9, 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, 2022, the decommissioning contingency for sold Gulf of Mexico properties (decommissioning contingency) balance totaled $1.2 billion. As further described in Note 12, 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 as well as current bids obtained from service providers. 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 23, 2023

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED OPERATIONS

	For the Year Ended December 31,		
	2022	2021	2020
	(In millions, except per common share data)		
REVENUES AND OTHER:			
Oil, natural gas, and natural gas liquids production revenues[1]	$ 9,028	$ 6,498	$ 4,037
Purchased oil and gas sales	1,855	1,487	398
Total revenues	10,883	7,985	4,435
Derivative instrument gains (losses), net	(107)	94	(223)
Gain on divestitures, net	1,180	67	32
Losses on previously sold Gulf of Mexico properties	(157)	(446)	—
Other, net	139	228	64
	11,938	7,928	4,308
OPERATING EXPENSES:			
Lease operating expenses	1,435	1,241	1,127
Gathering, processing, and transmission[1]	356	264	274
Purchased oil and gas costs	1,776	1,580	357
Taxes other than income	256	204	123
Exploration	146	127	274
General and administrative	462	357	290
Transaction, reorganization, and separation	26	22	54
Depreciation, depletion, and amortization	1,177	1,360	1,772
Asset retirement obligation accretion	117	113	109
Impairments	—	208	4,501
Financing costs, net	313	472	267
	6,064	5,948	9,148
NET INCOME (LOSS) BEFORE INCOME TAXES	5,874	1,980	(4,840)
Current income tax provision	1,507	652	176
Deferred income tax provision (benefit)	145	(74)	(112)
NET INCOME (LOSS) INCLUDING NONCONTROLLING INTERESTS	4,222	1,402	(4,904)
Net income (loss) attributable to noncontrolling interest - Sinopec	464	174	(121)
Net income attributable to noncontrolling interest - Altus	14	4	1
Net income attributable to noncontrolling interest - APA Corporation	278	—	—
Net income (loss) attributable to Altus Preferred Unit limited partners	(70)	162	76
NET INCOME (LOSS) ATTRIBUTABLE TO APA CORPORATION	$ 3,536	$ 1,062	$ (4,860)

(1) For revenues and gathering, processing, and transmission costs associated with Kinetik, refer to Note 7—Equity Method Interest for further detail.

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

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

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
NET INCOME (LOSS) INCLUDING NONCONTROLLING INTERESTS	$ 4,222	$ 1,402	$ (4,904)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Pension and postretirement benefit plan	(8)	7	(2)
Share of equity method interests other comprehensive income	—	1	—
COMPREHENSIVE INCOME (LOSS) INCLUDING NONCONTROLLING INTERESTS	4,214	1,410	(4,906)
Comprehensive income (loss) attributable to noncontrolling interest - Sinopec	464	174	(121)
Comprehensive income attributable to noncontrolling interest - Altus	14	4	1
Net income attributable to noncontrolling interest - APA Corporation	278	—	—
Comprehensive income (loss) attributable to Altus Preferred Unit limited partners	(70)	162	76
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO APA CORPORATION	$ 3,528	$ 1,070	$ (4,862)

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

APACHE CORPORATION AND SUBSIDIARIES
STATEMENT OF CONSOLIDATED CASH FLOWS

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss) including noncontrolling interests	$ 4,222	$ 1,402	$ (4,904)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Unrealized derivative instrument losses (gains), net	23	(69)	87
Gain on divestitures, net	(1,180)	(67)	(32)
Exploratory dry hole expense and unproved leasehold impairments	92	86	211
Depreciation, depletion, and amortization	1,177	1,360	1,772
Asset retirement obligation accretion	117	113	109
Impairments	—	208	4,501
Provision for (benefit from) deferred income taxes	145	(74)	(112)
Loss (gain) from extinguishment of debt	67	104	(160)
Losses on previously sold Gulf of Mexico properties	157	446	—
Other	(137)	(23)	102
Changes in operating assets and liabilities:			
Receivables	(55)	(393)	149
Inventories	(1)	(9)	19
Drilling advances and other current assets	(12)	60	(29)
Deferred charges and other long-term assets	70	(42)	(13)
Accounts payable	12	205	(167)
Receivable/payable with APA Corporation	—	40	—
Accrued expenses	293	127	(163)
Deferred credits and noncurrent liabilities	(138)	31	18
NET CASH PROVIDED BY OPERATING ACTIVITIES	4,852	3,505	1,388
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to upstream oil and gas property	(1,503)	(934)	(1,270)
Leasehold and property acquisitions	(37)	(9)	(4)
Noncurrent receivable from APA Corporation	(832)	—	—
Contributions to Altus equity method interests	—	(28)	(327)
Proceeds from asset divestitures	778	256	166
Proceeds from sale of Kinetik shares	224	—	—
Deconsolidation of Altus cash and cash equivalents	(143)	—	—
Other, net	28	49	(31)
NET CASH USED IN INVESTING ACTIVITIES	(1,485)	(666)	(1,466)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from Apache credit facility, net	138	392	150
Proceeds from Altus credit facility	—	33	228
Proceeds from (payments on) note payable to APA Corporation, net	(835)	78	—
Fixed rate debt borrowings	—	—	1,238
Payments on fixed-rate debt	(1,493)	(1,795)	(1,243)
Distributions to noncontrolling interest - Sinopec	(362)	(279)	(91)
Distributions to Altus Preferred Unit limited partners	(11)	(46)	(23)
Distributions to APA Corporation	(894)	(1,182)	—
Dividends paid	—	(9)	(123)
Other, net	(4)	(14)	(43)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(3,461)	(2,822)	93
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(94)	17	15
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	279	262	247
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 185	$ 279	$ 262
SUPPLEMENTARY CASH FLOW DATA:			
Interest paid, net of capitalized interest	$ 322	$ 442	$ 419
Income taxes paid, net of refunds	1,431	633	212
Non-cash financing adjustment: APA's assumption of Apache's borrowings on its syndicated credit facility	680	—	—

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

APACHE CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

	December 31,	
	2022[(1)]	2021[(1)]
	(In millions, except share data)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents ($132 related to Altus VIE)	$ 185	$ 279
Receivables, net of allowance of $117 and $109	1,424	1,390
Other current assets (Note 6) ($9 related to Altus VIE)	993	649
Accounts receivable from APA Corporation	—	77
	2,602	2,395
PROPERTY AND EQUIPMENT:		
Oil and gas, on the basis of successful efforts accounting:	41,245	40,474
Gathering, processing, and transmission facilities ($209 related to Altus VIE)	449	673
Other ($3 related to Altus VIE)	613	1,126
Less: Accumulated depreciation, depletion, and amortization ($25 related to Altus VIE)	(34,350)	(34,213)
	7,957	8,060
OTHER ASSETS:		
Equity method interests (Note 7) ($1,365 related to Altus VIE)	624	1,365
Decommissioning security for sold Gulf of Mexico properties (Note 12)	217	640
Deferred charges and other ($6 related to Altus VIE)	571	581
Noncurrent receivable from APA Corporation	869	—
Note receivable from APA Corporation (Note 2)	1,415	1,352
	$ 14,255	$ 14,393
LIABILITIES, NONCONTROLLING INTEREST, AND EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable ($12 related to Altus VIE)	$ 646	$ 651
Note payable to APA Corporation (Note 2)	—	195
Current debt	2	215
Other current liabilities (Note 8) ($15 related to Altus VIE)	2,049	1,170
	2,697	2,231
LONG-TERM DEBT (Note 10) ($657 related to Altus VIE)	4,885	7,295
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES:		
Income taxes	314	148
Asset retirement obligation ($68 related to Altus VIE)	1,936	2,089
Decommissioning contingency for sold Gulf of Mexico properties (Note 12)	738	1,086
Other ($67 related to Altus VIE)	443	572
	3,431	3,895
REDEEMABLE NONCONTROLLING INTEREST - ALTUS PREFERRED UNIT LIMITED PARTNERS (Note 14)	—	712
EQUITY (DEFICIT):		
Common stock, $0.625 par, 1,000 and 1,000 shares authorized, respectively, 1,000 and 1,000 shares issued, respectively	—	—
Paid-in capital	8,025	8,677
Accumulated deficit	(5,781)	(9,317)
Accumulated other comprehensive income	14	22
EQUITY (DEFICIT) ATTRIBUTABLE TO APA CORPORATION	2,258	(618)
Noncontrolling interest - Sinopec	922	820
Noncontrolling interest - APA Corporation	62	—
Noncontrolling interest - Altus	—	58
TOTAL EQUITY	3,242	260
	$ 14,255	$ 14,393

(1) The Altus VIE amounts are disclosed as of December 31, 2021. All Altus balances were deconsolidated as of February 22, 2022. Refer to Note 1—Summary of Significant Accounting Policies and Note 3—Acquisitions and Divestitures for further detail.

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

APACHE 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 (Loss)	PARENT COMPANY EQUITY (DEFICIT)	Noncontrolling Interests	TOTAL EQUITY (DEFICIT)
					(In millions)				
BALANCE AT DECEMBER 31, 2019	$ 555	$ 261	$ 11,769	$ (5,601)	$ (3,190)	$ 16	$ 3,255	$ 1,210	$ 4,465
Net loss attributable to APA Corporation	—	—	—	(4,860)	—	—	(4,860)	—	(4,860)
Net loss attributable to noncontrolling interest - Sinopec	—	—	—	—	—	—	—	(121)	(121)
Net income attributable to noncontrolling interest - Altus	—	—	—	—	—	—	—	1	1
Net income attributable to Altus Preferred Unit limited partners	76	—	—	—	—	—	—	—	—
Distributions paid to Altus Preferred Unit limited partners	(23)	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest - Egypt	—	—	—	—	—	—	—	(91)	(91)
Common dividends ($0.10 per share)	—	—	(38)	—	—	—	(38)	—	(38)
Common stock activity, net	—	1	(18)	—	—	—	(17)	—	(17)
Compensation expense	—	—	23	—	—	—	23	—	23
Other	—	—	(1)	—	1	(2)	(2)	(5)	(7)
BALANCE AT DECEMBER 31, 2020	$ 608	$ 262	$ 11,735	$ (10,461)	$ (3,189)	$ 14	$ (1,639)	$ 994	$ (645)
Net income attributable to APA Corporation	—	—	—	1,062	—	—	1,062	—	1,062
Net income attributable to noncontrolling interest - Sinopec	—	—	—	—	—	—	—	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)
Distributions to APA Corporation	—	—	(890)	—	—	—	(890)	—	(890)
Common dividends ($0.025 per share)	—	—	(9)	—	—	—	(9)	—	(9)
APA Corporation share exchange	—	(262)	(2,927)	—	3,189	—	—	—	—
Holding Company Reorganization	—	—	757	82	—	—	839	—	839
Other	—	—	11	—	—	8	19	(15)	4
BALANCE AT DECEMBER 31, 2021	$ 712	$ —	$ 8,677	$ (9,317)	$ —	$ 22	$ (618)	$ 878	$ 260
Net income attributable to APA Corporation	—	—	—	3,536	—	—	3,536	—	3,536
Net income attributable to noncontrolling interest - APA	—	—	—	—	—	—	—	278	278
Net income attributable to noncontrolling interest - Sinopec	—	—	—	—	—	—	—	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)
Distributions to APA Corporation	—	—	(678)	—	—	—	(678)	(216)	(894)
Deconsolidation of Altus	(642)	—	—	—	—	—	—	(72)	(72)
Other	—	—	26	—	—	(8)	18	—	18
BALANCE AT DECEMBER 31, 2022	$ —	$ —	$ 8,025	$ (5,781)	$ —	$ 14	$ 2,258	$ 984	$ 3,242

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

Nature of Operations

Apache Corporation (Apache or the Company) is an independent energy company that explores for, develops, and produces natural gas, crude oil, and natural gas liquids. The Company's upstream business has exploration and production operations in three geographic areas: the United States (U.S.), Egypt, and offshore the U.K. in the North Sea (North Sea). Prior to the BCP Business Combination defined below, Apache's midstream business was operated by Altus Midstream Company (ALTM) through its subsidiary Altus Midstream LP (collectively, Altus). Altus owned, developed, and operated a midstream energy asset network in the Permian Basin of West Texas.

On March 1, 2021, Apache consummated a holding company reorganization (the Holding Company Reorganization), pursuant to which Apache became a direct, wholly owned subsidiary of APA Corporation (APA), and all of Apache's outstanding shares automatically converted into equivalent corresponding shares of APA. Pursuant to the Holding Company Reorganization, APA became the successor issuer to Apache pursuant to Rule 12g-3(a) under the Exchange Act and replaced Apache as the public company trading on the Nasdaq Global Select Market under the ticker symbol "APA." The Holding Company Reorganization modernized APA's operating and legal structure, making it more consistent with other companies that have affiliates operating around the globe. Refer to Note 2—Transactions with Parent Affiliate for more detail.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Accounting policies used by Apache 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 Apache and its subsidiaries after elimination of intercompany balances and transactions. Apache's consolidated financial statements reflect the impacts of the Holding Company Reorganization on a prospective basis, and results prior to completion of the Holding Company Reorganization have not been restated. Refer to Note 2—Transactions with Parent Affiliate for more detail.

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 outside ownership in the net assets of a consolidated subsidiary of Apache and are reflected separately in the Company's financial statements.

In conjunction with the ratification of a new merged concession agreement with the Egyptian General Petroleum Corporation (EGPC) in December 2021, Apache modified partnership agreements for certain consolidated subsidiaries. Apache subsequently determined that one of its limited partnership subsidiaries, which has control over Apache's Egyptian operations, qualified as a variable interest entity (VIE) under GAAP. Apache continues to consolidate this limited partnership subsidiary because the Company has concluded that it has a controlling financial interest in the Egyptian operations and was determined to be the primary beneficiary of the VIE. For all periods presented, Sinopec International Petroleum Exploration and Production Corporation (Sinopec) has owned a one-third minority participation in the Company's consolidated Egypt oil and gas business as a noncontrolling interest. Under the modified partnership agreements, APA owns a minority participation in the remaining two-thirds of its consolidated Egypt oil and gas business as a noncontrolling interest. Refer to Note 2—Transactions with Parent Affiliate for detail regarding APA's noncontrolling interest. All noncontrolling interests are reflected as a separate component of equity in the Company's consolidated balance sheet.

Additionally, prior to the BCP Business Combination 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 Apache consolidated because a wholly owned subsidiary of Apache had a controlling financial interest and was determined to be the primary beneficiary. Additionally, the assets of ALTM could only be used to settle obligations of ALTM. There was no recourse to the Company for ALTM's liabilities.

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). 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 3—Acquisitions and Divestitures for further detail.

The stockholders agreement entered into by and among the Company, ALTM, BCP, and other related and affiliated entities provides that the Company, through one of its wholly owned subsidiaries, retains the ability to designate a director to the board of directors of Kinetik for so long as the Company and its affiliates beneficially own 10 percent or more of Kinetik's outstanding common stock. Based on this board representation, combined with the Company's stock ownership, management determined it has significant influence over Kinetik. 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 7—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 3—Acquisitions and Divestitures), the fair value of equity method interests (refer to "Equity Method Interests" within this Note 1 and Note 7—Equity Method Interests), the assessment of asset retirement obligations (refer to Note 9—Asset Retirement Obligation), the estimate of income taxes (refer to Note 11—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 12—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 19—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).

Recurring fair value measurements are presented in further detail in Note 5—Derivative Instruments and Hedging Activities, Note 7—Equity Method Interests, Note 10—Debt and Financing Costs, Note 13—Retirement and Deferred Compensation Plans, and Note 14—Redeemable Noncontrolling Interest — Altus.

The Company also uses fair value measurements on a nonrecurring basis when certain qualitative assessments of its assets indicate a potential impairment. The following table presents a summary of asset impairments recorded in connection with fair value assessments:

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Oil and gas proved property	$ —	$ —	$ 4,319
Gathering, processing, and transmission facilities	—	—	68
Equity method interests	—	160	—
Goodwill	—	—	87
Inventory and other	—	48	27
Total Impairments	$ —	$ 208	$ 4,501

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 the EPIC crude oil pipeline (EPIC) 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 3—Acquisitions and Divestitures for further detail on the BCP Business Combination. 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.

For the year ended December 31, 2020, the Company recorded asset impairments totaling $4.5 billion in connection with non-recurring fair value assessments. Given the crude oil price collapse on lower demand and economic activity resulting from the coronavirus disease 2019 (COVID-19) global pandemic and related governmental actions, the Company assessed its oil and gas property and gathering, processing, and transmission (GPT) facilities for impairment based on the net book value of its assets as of March 31, 2020. The Company recognized proved property impairments of $3.9 billion, $354 million, and $7 million in the U.S., Egypt, and North Sea, respectively, all of which were impaired to their estimated fair values as a result of lower forecasted commodity prices, changes to planned development activity, and increasing market uncertainty. Similarly, the Company recognized GPT facility impairments of $68 million in Egypt. These impairments are discussed in further detail below in "Property and Equipment - Oil and Gas Property" and "Property and Equipment - Gathering, Processing, and Transmission Facilities."

The Company also performed an interim impairment analysis of the goodwill related to its Egypt reporting unit. Reductions in estimated net present value of expected future cash flows from oil and gas properties resulted in implied fair values below the carrying values of the Company's Egypt reporting unit. As a result of these assessments, the Company recognized non-cash impairments of the entire amount of recorded goodwill in the Egypt reporting unit of $87 million in the first quarter of 2020.

During the remainder of 2020, the Company recorded additional proved property impairments totaling $20 million in Egypt, as well as $13 million for the early termination of drilling rig leases, $5 million for inventory revaluations, and $9 million of other asset impairments, all in the U.S.

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 Apache-related production volumes, the Company also sells commodity volumes purchased from third-parties to provide flexibility to fulfill sales obligations and commitments. Under these short-term 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.

The Company'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. Revenues related to Egypt's tax volumes are considered revenue from a non-customer.

On December 27, 2021, the Company announced the ratification of a new merged concession agreement (MCA) with the Egyptian Ministry of Petroleum and the EGPC, having an effective date of April 1, 2021. The MCA consolidated 98 percent of gross acreage and 90 percent of gross production under one concession agreement and refreshed the existing development lease terms for 20 years and exploration leases for 5 years. The consolidated concession has a single cost recovery pool to provide improved access to cost recovery, a fixed 40 percent cost recovery limit, and a fixed profit-sharing rate of 30 percent for all the Company's production covered under the new concession. For all periods presented, Sinopec has owned a one-third minority participation in the Company's consolidated Egypt oil and gas business as a noncontrolling interest. Under the modified partnership agreements, APA owns a minority participation in the remaining two-thirds of its consolidated Egypt oil and gas business as a noncontrolling interest.

Refer to Note 18—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 APA, which were fully eliminated upon consolidation.

Payment Terms and Contract Balances

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. Receivables from contracts with customers, including receivables for purchased oil and gas sales and net of allowance for credit losses, were $1.3 billion at each of December 31, 2022 and 2021.

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, 2022 and 2021, the Company had $185 million and $279 million, respectively, of cash and cash equivalents. As of December 31, 2021, approximately $132 million of cash was held by Altus, which was deconsolidated on February 22, 2022. The Company had no restricted cash as of December 31, 2022 and 2021.

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,		
	2022	2021	2020
		(In millions)	
Allowance for credit loss at beginning of year	$ 109	$ 95	$ 88
Additional provisions for the year	9	19	7
Uncollectible accounts written off, net of recoveries	(1)	(5)	—
Allowance for credit loss at end of year	$ 117	$ 109	$ 95

Receivable from / Payable to APA

Receivable from or payable to APA represents the net result of Apache's administrative and support services provided to APA and other miscellaneous cash management transactions to be settled between the two affiliated entities. Cash will be transferred to Apache or paid to APA over time in order to manage affiliate balances for cash management purposes. Refer to Note 2—Transactions with Parent Affiliate for more detail.

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.

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.

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.

The significant decline in crude oil and natural gas prices, as well as longer-term commodity price outlooks, related to reduced demand for oil and natural gas as a result of the COVID-19 pandemic and related governmental actions indicated possible impairment of the Company's proved and unproved oil and gas properties in early 2020. In addition to estimating risk-adjusted reserves and future production volumes, estimated future commodity prices are the largest driver in variability of undiscounted pre-tax cash flows. Expected cash flows were estimated based on management's views of published West Texas Intermediate (WTI), Brent, and Henry Hub forward pricing as of the balance sheet dates. Other significant assumptions and inputs used to calculate estimated future cash flows include estimates for future development activity, exploration plans and remaining lease terms. A 10 percent discount rate, based on a market-based weighted-average cost of capital estimate, was applied to the undiscounted cash flow estimate to value all of the Company's asset groups that were subject to impairment charges in 2020.

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

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Proved properties:			
U.S.	$ —	$ —	$ 3,938
Egypt	—	—	374
North Sea	—	—	7
Total proved properties	$ —	$ —	$ 4,319
Unproved properties:			
U.S.	$ 20	$ 22	$ 92
Egypt	4	8	8
North Sea	—	1	1
Total unproved properties	$ 24	$ 31	$ 101

Proved properties impaired had an aggregate fair value as of the most recent date of impairment of $1.9 billion for 2020.

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 3—Acquisitions and Divestitures for more detail.

Gathering, Processing, and Transmission (GPT) Facilities

GPT facilities totaled $449 million and $673 million at December 31, 2022 and 2021, respectively, with accumulated depreciation for these assets totaling $367 million and $386 million for the respective periods. As a result of the BCP Business Combination, the Company deconsolidated $183 million of Altus GPT net assets on February 22, 2022. 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 Apache-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.

The Company assessed its long-lived infrastructure assets for impairment as of March 31, 2020, and recorded an impairment of $68 million on its GPT facilities in Egypt during the first quarter of 2020. The fair values of the impaired assets, which were determined to be $46 million, were estimated using the income approach, which considers internal estimates based on future throughput volumes from applicable development concessions in Egypt and estimated costs to operate. These assumptions were applied based on throughput assumptions developed in relation to the oil and gas proved property impairment assessment, as discussed above, to develop future cash flow projections that were then discounted to estimated fair value, using a 10 percent discount rate, based on a market-based weighted-average cost of capital estimate. The Company has classified these non-recurring fair value measurements as Level 3 in the fair value hierarchy.

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 $206 million and $225 million at December 31, 2022 and 2021, 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.

Goodwill

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. The Company currently carries no goodwill, but, in comparative periods, it was recorded in "Deferred charges and other" in the Company's consolidated balance sheet. The Company assessed the carrying amount of goodwill by testing for impairment annually and when impairment indicators arose. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The Company assessed each country as a reporting unit, with Egypt being the only reporting unit to have associated goodwill during the periods presented. The fair value of the reporting unit was determined and compared to the book value of the reporting unit. If the fair value of the reporting unit was less than the book value, including goodwill, then goodwill was written down to its implied fair value through a charge to expense.

Reductions in estimated net present value of expected future cash flows from oil and gas properties during 2020 resulted in implied fair values below the carrying values of the Company's Egypt reporting unit. As a result of this assessment, the Company recognized non-cash impairments of the entire amount of recorded goodwill in the Egypt reporting unit of $87 million in 2020. This goodwill impairment was recorded in "Impairments" in the Company's statement of consolidated operations. The Company has no goodwill recognized as of December 31, 2022, 2021, or 2020.

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.

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 current fair value of its investment in EPIC was below carrying value. Altus subsequently determined that this loss in value to be other than temporary. As such, in the fourth quarter of 2021, Altus recorded an impairment charge of $160 million on its equity method interest in EPIC. The fair value of the impaired interest was determined using the income approach. The income approach considered estimates of future throughput volumes, tariff rates, and costs. These assumptions were applied to develop future cash flow projections that were then discounted to estimated fair value, using a discount rate believed to be consistent with that which would be applied by market participants. Altus classified this nonrecurring fair value measurement as Level 3 in the fair value hierarchy. Refer to Note 7—Equity Method Interests for further details of the Company's equity method interests.

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 12—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 5—Derivative Instruments and Hedging Activities for further information.

Income Taxes

Apache 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.

Apache is a directly owned subsidiary of APA Corporation and is included in APA Corporation and Subsidiaries' U.S. Federal income tax return. The Company's financial statements recognize the current and deferred income tax consequences that result from Apache's activities during the current period pursuant to the provisions of ASC Topic 740 "Income Taxes" as if the Company were a separate taxpayer rather than a member of APA Corporation's consolidated income tax return group.

Stock-Based Compensation

Prior to consummation of the Holding Company Reorganization, Apache granted 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 APA'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, which were assumed by APA pursuant to the Holding Company Reorganization, and related accounting policies are defined and described more fully in Note 15—Capital Stock.

Transaction, Reorganization, and Separation (TRS)

In recent years, the Company streamlined its portfolio through strategic divestitures and centralized certain operational activities in an effort to capture greater efficiencies and cost savings through shared services. In light of the continued streamlining of the Company's asset portfolio through divestitures and strategic transactions, in late 2019 management initiated a comprehensive redesign of the Company's organizational structure and operations. Efforts related to this organization were substantially completed during 2020. The Company incurred and paid a cumulative total of $79 million of reorganization costs through December 31, 2020. An additional $15 million and $17 million of reorganization costs were incurred during the years ended December 31, 2022 and 2021, respectively, primarily related to ongoing consulting and separation activities in the Company's international operations.

The Company recorded $26 million, $22 million, and $54 million of TRS costs in 2022, 2021, and 2020, respectively. TRS costs incurred in 2022 comprised $15 million related to the reorganization, including $9 million for consulting costs and $6 million of separation costs, and $11 million for costs associated with the BCP Business Combination. TRS costs incurred in 2021 comprised $17 million related to the reorganization, including $11 million for consulting costs and $6 million of separation costs, and $5 million for costs associated with the BCP Business Combination. TRS costs incurred in 2020 relate to $51 million of separation costs associated with the reorganization, $2 million for transaction consulting fees, and $1 million of office closure costs.

2. TRANSACTIONS WITH PARENT AFFILIATE

The Company completed the Holding Company Reorganization on March 1, 2021, and sold to APA all of the equity in the three Apache subsidiaries through which Apache's interests in Suriname and the Dominican Republic were held. The Company accounted for the divestiture of its subsidiaries as a transfer to an affiliate entity under common control and no longer consolidates the subsidiaries for periods subsequent to the Holding Company Reorganization. The carrying value of the net assets transferred was $483 million, which included approximately $292 million of cash and cash equivalents, $163 million of oil and gas properties, and working capital items. The Company continues to hold its existing assets in the U.S., Egypt, and the U.K.

The Holding Company Reorganization gave rise to a note payable by APA to Apache. The note has a seven-year term, maturing on February 29, 2028, and bears interest at a rate of 4.5 percent per annum, payable semi-annually, subject to APA's option to allow accrued interest to convert to principal (PIK) during the first 5.5 years of the note's term (to August 31, 2026). The note is guaranteed by each of the three subsidiaries sold by Apache to APA. The Company recognized interest income on this note of $63 million and $51 million during 2022 and 2021, respectively. The interest income related to this note is reflected in "Financing costs, net" on the Company's statement of consolidated operations. Apache allowed interest accrued from March 1, 2021 through August 31, 2022, totaling $93 million, to PIK pursuant to the note.

In the fourth quarter of 2021, in conjunction with the ratification of a new merged concession agreement (MCA) with EGPC, Apache entered into an agreement with APA under which the historical value of existing concessions prior to ratifying the MCA was retained by Apache, with any excess value from the MCA terms being allocated to APA. Sinopec owns a one-third minority participation in the Company's consolidated Egypt oil and gas business, and a portion of the remaining net income and distributable cash flow is allocated to APA in accordance with the terms of the agreement. In 2022, approximately 30 percent of the remaining net income and distributable cash flow for the Company's Egyptian operations was allocated to APA. Apache consolidates its Egyptian operations, with noncontrolling interests reflected as a separate component in the Company's consolidated balance sheet. During 2022, the Company recorded net income attributable to APA's noncontrolling interest of $278 million, and distributed $216 million of cash to APA in association with its noncontrolling interest.

The Company continues to provide administrative and support operations for certain APA subsidiaries with interest in the U.S., Suriname, and the Dominican Republic. The Company is reimbursed by APA for employee costs, certain internal costs, and third-party costs paid by the Company in connection with its role as service provider. All reimbursements are based on actual costs incurred, and no market premium is applied by the Company to APA. The Company incurred $18 million and $17 million in reimbursable corporate overhead charges during 2022 and 2021, respectively.

In August 2021, Apache entered into a promissory note with APA under which Apache could borrow up to $250 million from APA at APA's discretion. The note had a term of one year and bore interest at a variable rate per annum equal to the monthly, short-term applicable federal rate, payable semi-annually. As of December 31, 2021, there was $195 million outstanding under this note, which was reflected as "Note payable to APA Corporation" on the Company's consolidated balance sheet. All remaining borrowings were fully repaid prior to maturity on August 4, 2022.

In April 2022, Apache made a promissory note payable to APA in the original principal amount of $680 million. Apache made the note in consideration for APA's assumption under its U.S. dollar denominated syndicated facility on April, 29, 2022 of Apache's borrowings outstanding upon the simultaneous termination of its 2018 syndicated facility, as described in Note 10—Debt and Financing Costs. The non-interest-bearing note had a term of one year, maturing on April 28, 2023, and was fully repaid by September 30, 2022. Apache repaid $331 million on the note during the second quarter of 2022 and the remaining $349 million during the third quarter of 2022.

Receivable from APA Corporation, totaling $869 million and $77 million as of December 31, 2022 and 2021, respectively, represents the net result of Apache's administrative and support services provided to APA and other miscellaneous cash management transactions to be settled between the two affiliated entities. Cash will be transferred to Apache over time in order to manage affiliate balances for cash management purposes.

From time to time, the Company may, at its discretion, make distributions of capital to APA Corporation. During 2022, the Company made capital distributions totaling $894 million, primarily in support of APA Corporation's share repurchase program, dividend payments made by APA, and distributions for APA's noncontrolling interest during the period. During 2021, the Company made capital distributions totaling $839 million related to dividend payments made by APA.

3. ACQUISITIONS AND DIVESTITURES

2022 Activity

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 a gain of approximately $36 million, upon closing of these transactions.

During the first quarter of 2022, the Company completed a previously announced transaction to sell 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 share of ALTM's deconsolidated balance sheet and the fair value of its approximate 20 percent retained ownership in the combined entity. A summary of components of the gain, including the ALTM balance sheet amounts deconsolidated at the time of close, is included below:

	As of February 22, 2022	
	(In millions)	
Fair value of Kinetik Class A Common Stock held by Company	$	802
ASSETS:		
Cash and cash equivalents	$	143
Other current assets		29
Property and equipment, net		184
Equity method interests		1,367
Other noncurrent assets		12
Total assets deconsolidated	$	1,735
LIABILITIES:		
Current liabilities	$	3
Long-term debt		657
Other noncurrent liabilities		168
Total liabilities deconsolidated	$	828
NONCONTROLLING INTERESTS:		
Redeemable noncontrolling interest preferred unit limited partners	$	642
Noncontrolling interest-Altus		72
Total noncontrolling interests deconsolidated	$	714
Net effect of deconsolidating balance sheet	$	(193)
Gain on deconsolidation of ALTM	$	609

During the first quarter of 2022, the Company sold four million of its shares of Kinetik Class A Common Stock for cash proceeds of $224 million and recognized a loss of $25 million, including transaction fees. Refer to Note 7—Equity Method Interests for further detail. In connection with this secondary offering, the Company agreed that, within 24 months of closing the offering, it will invest a minimum of $100 million of the proceeds of the offering for new well drilling and completion activity at the Alpine High play in the Delaware Basin, where Kinetik has exclusive gas and NGL gathering and processing rights. The Company has invested approximately half of this commitment as of year-end 2022.

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.

2020 Activity

During 2020, the Company completed leasehold and property acquisitions, primarily in the Permian Basin, for total cash consideration of $4 million. Also during 2020, the Company completed the sale of certain non-core assets and leasehold, primarily in the Permian Basin, in multiple transactions for total cash proceeds of $87 million, and recognized a gain of $13 million. The Company also recognized a gain of $19 million during 2020 in connection with a joint venture agreement with TotalEnergies (formerly Total S.A.) to explore and develop Block 58 offshore Suriname.

4. CAPITALIZED EXPLORATORY WELL COSTS

The following summarizes the changes in capitalized exploratory well costs for the years ended December 31, 2022, 2021, and 2020. 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,		
	2022	2021	2020
		(In millions)	
Capitalized well costs at beginning of year	$ 46	$ 197	$ 141
Additions pending determination of proved reserves	138	62	226
Divestitures and other	—	(163)	(38)
Reclassifications to proved properties	(110)	(40)	(56)
Charged to exploration expense	(24)	(10)	(76)
Capitalized well costs at end of year	$ 50	$ 46	$ 197

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:

	2022	2021	2020
		(In millions)	
Exploratory well costs capitalized for a period of one year or less	$ 34	$ 13	$ 184
Exploratory well costs capitalized for a period greater than one year	16	33	13
Capitalized well costs at end of year	$ 50	$ 46	$ 197
Number of projects with exploratory well costs capitalized for a period greater than one year	10	9	5

Projects with suspended 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. Suspended exploratory well costs capitalized for a period greater than one year since the completion of drilling were $16 million at December 31, 2022. 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, 2021 totaled $24 million. These expenses pertain to projects in the North Sea where development is no longer progressing.

The following table summarizes aging by geographic area of those exploratory well costs that, as of December 31, 2022, have been capitalized for a period greater than one year, categorized by the year in which drilling was completed:

	Total	2021	2020	2019 and Prior
		(In millions)		
Egypt	$ 14	$ 5	$ —	$ 9
North Sea	2	2	—	—
	$ 16	$ 7	$ —	$ 9

5. 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 may utilize 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.

In December 2022, counterparty agreements for Apache's commodity derivative instruments were transferred from Apache to APA Corporation. As of the dates of transfer, Apache's consolidated balance sheet reflected derivative liabilities totaling $37 million, which represented the fair values of the commodity derivative instruments on those dates. The resulting impacts of the transfer to APA Corporation were the realization of the mark-to-market loss of $37 million on Apache's statement of consolidated operation and the derecognition of open derivative positions on Apache's consolidated balance sheet. Apache had no outstanding derivative positions as of December 31, 2022.

Embedded Derivatives

Altus Preferred Units Embedded Derivative

The Altus Preferred Units embedded derivative was deconsolidated as of March 31, 2022 as part of the BCP Business Combination. Refer to Note 3—Acquisitions and Divestitures for discussion of the BCP Business Combination and Note 14—Redeemable Noncontrolling Interest—Altus for a description of the Altus Preferred Units and associated embedded derivative.

Pipeline Capacity Embedded Derivatives

During the fourth quarter of 2019 and first quarter of 2020, the Company entered into agreements to assign a portion of its contracted capacity under an existing transportation agreement to third parties. Embedded in these agreements were arrangements under which the Company received payments calculated based on pricing differentials between Houston Ship Channel and Waha during the calendar years 2020 and 2021. This feature required bifurcation and measurement of the change in market value throughout 2020 and 2021. Unrealized gains and losses in the fair value of this feature were recorded as "Derivative instrument gains (losses), net" under "Revenues and Other" in the statement of consolidated operations, and the balance at the end of December 31, 2021 will be amortized into income over the original tenure of the host contract.

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, 2022						
Assets:						
Commodity derivative instruments	$ —	$ —	$ —	$ —	$ —	$ —
Liabilities:						
Commodity derivative instruments	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2021						
Liabilities:						
Commodity derivative instruments	$ —	$ 10	$ —	$ 10	$ —	$ 10
Pipeline capacity embedded derivatives	—	46	—	46	—	46
Preferred Units embedded derivative	—	—	57	57	—	57

(1) Derivative fair values were 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 were not actively quoted in the open market. The Company primarily used 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 were reflected as either assets or liabilities at fair value in the consolidated balance sheet. These fair values were recorded by netting asset and liability positions where counterparty master netting arrangements contained provisions for net settlement. The carrying value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet were as follows:

	For the Year Ended December 31,	
	2022	2021
	(In millions)	
Current Assets: Other current assets	$ —	$ —
Other Assets: Deferred charges and other	—	—
Total derivative assets	$ —	$ —
Current Liabilities: Other current liabilities	$ —	$ 4
Deferred Credits and Other Noncurrent Liabilities: Other	—	109
Total derivative liabilities	$ —	$ 113

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,		
	2022	2021	2020
		(In millions)	
Realized:			
Commodity derivative instruments	$ (72)	$ 25	$ (135)
Foreign currency derivative instruments	(13)	—	(1)
Realized gain (loss), net	(85)	25	(136)
Unrealized:			
Commodity derivative instruments	9	(20)	11
Pipeline capacity embedded derivatives	—	7	(61)
Foreign currency derivative instruments	—	—	(1)
Preferred Units embedded derivative	(31)	82	(36)
Unrealized gain (loss), net	(22)	69	(87)
Derivative instrument gains (losses), net	$ (107)	$ 94	$ (223)

Derivative instrument gains and losses were 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 were reflected in the statement of consolidated cash flows separately as "Unrealized derivative instrument losses (gains), net" in "Adjustments to reconcile net income (loss) to net cash provided by operating activities."

6. OTHER CURRENT ASSETS

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

	2022	2021
	(In millions)	
Inventories	$ 425	$ 438
Drilling advances	64	55
Prepaid assets and other	54	56
Current decommissioning security for sold Gulf of Mexico assets	450	100
Total Other current assets	$ 993	$ 649

7. EQUITY METHOD INTERESTS

The Kinetik Class A Common Stock held by the Company is 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 and dividends received are recorded as a component of "Other, net" under "Revenues and other" in the Company's statement of consolidated operations.

The initial interest in Kinetik was measured at fair value based on the Company's ownership of approximately 12.9 million shares of Kinetik Class A Common stock as of February 22, 2022. In March 2022, the Company sold four million of its shares of Kinetik Class A Common Stock for a loss, including underwriters fees, of $25 million, which was recorded as a component of "Gain on divestitures, net" under "Revenues and other" in the Company's statement of consolidated operations. Refer to Note 3–Acquisitions and Divestitures for further detail.

During the second quarter of 2022, Kinetik issued a two-for-one split of its Common Stock. Also during 2022, the Company received approximately 1.1 million shares of Kinetik's Class A Common Stock as paid-in-kind dividends. Finally, in 2022, the Company recorded fair value adjustments on its ownership in Kinetik totaling a gain of approximately $32 million. The Company's ownership of 18.9 million shares represented approximately 13 percent of Kinetik's outstanding Class A Common Stock as of December 31, 2022.

The following table presents the activity in the Company's equity method interest in Kinetik for the year ended December 31, 2022:

	Kinetik Holdings Inc
	(In millions)
Balance at December 31, 2021	$ —
Initial interest upon closing the BCP Business Combination	802
Sale of Class A shares	(250)
Paid-in-kind dividend	40
Fair value adjustments	32
Balance at December 31, 2022	$ 624

During the year ending December 31, 2022, the Company recorded GPT costs for midstream services provided by Kinetik subsequent to the close of the BCP Business Combination transaction totaling $91 million. As of December 31, 2022, the Company has recorded accrued GPT costs payable to Kinetik of approximately $17 million. In addition, the Company sold natural gas and NGLs to Kinetik during 2022 totaling $8 million. As of December 31, 2022, the Company has recorded accrued receivables from Kinetik of approximately $8 million.

Prior to the deconsolidation of Altus on February 22, 2022, the Company, through its ownership of Altus, had the following equity method interests in four Permian Basin long-haul pipeline entities, which were accounted for under the equity method of accounting at December 31, 2021. For each of the equity method interests, Altus had the ability to exercise significant influence based on certain governance provisions and its participation in activities and decisions that impact the management and economic performance of the equity method interests. The table below presents the ownership percentages held by the Company and associated carrying values for each entity:

	Interest	December 31, 2021
		(In millions)
Gulf Coast Express Pipeline LLC	16.0 %	$ 274
EPIC Crude Holdings, LP	15.0 %	—
Permian Highway Pipeline LLC	26.7 %	630
Shin Oak Pipeline (Breviloba, LLC)	33.0 %	461
Total Altus equity method interests		$ 1,365

The following table presents the activity in Altus' equity method interests for the years ended December 31, 2022 and 2021:

	Gulf Coast Express Pipeline LLC	EPIC Crude Holdings, LP	Permian Highway Pipeline LLC	Breviloba, LLC	Total
			(In millions)		
Balance at December 31, 2020	$ 284	$ 176	$ 615	$ 480	$ 1,555
Capital contributions	—	2	26	—	28
Distributions	(50)	—	(74)	(49)	(173)
Equity income (loss), net	40	(19)	63	30	114
Accumulated other comprehensive loss	—	1	—	—	1
Impairment(1)	—	(160)	—	—	(160)
Balance at December 31, 2021	274	—	630	461	1,365
Capital contributions	—	2	—	—	2
Distributions	(5)	—	(9)	(7)	(21)
Equity income (loss), net	8	(2)	10	5	21
Deconsolidation of Altus	(277)	—	(631)	(459)	(1,367)
Balance at December 31, 2022	$ —	$ —	$ —	$ —	$ —

(1) Prior to the deconsolidation of Altus on February 22, 2022, the Company impaired its investment in EPIC in the fourth quarter of 2021. Refer to Note 1—Summary of Significant Accounting Policies for further details on this impairment charge.

For discussion of the financial statement impacts related to the deconsolidation of ALTM, refer to Note 3—Acquisitions and Divestitures.

8. OTHER CURRENT LIABILITIES

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

	2022	2021
	(In millions)	
Accrued operating expenses	$ 139	$ 129
Accrued exploration and development	300	206
Accrued compensation and benefits	514	292
Accrued interest	96	107
Accrued income taxes	90	28
Current asset retirement obligation	55	41
Current operating lease liability	167	99
Current decommissioning contingency for sold Gulf of Mexico properties	450	100
Other	238	168
Total Other current liabilities	$ 2,049	$ 1,170

9. ASSET RETIREMENT OBLIGATION

The following table describes changes to the Company's asset retirement obligation (ARO) liability for the years ended December 31, 2022 and 2021:

	For the Year Ended December 31, 2022	2021
	(In millions)	
Asset retirement obligation at beginning of the year	$ 2,130	$ 1,944
Liabilities incurred	4	3
Liabilities divested	(73)	(44)
Liabilities settled	(39)	(32)
Accretion expense	117	113
Revisions in estimated liabilities	(148)	146
Asset retirement obligation at end of the year	1,991	2,130
Less current portion	(55)	(41)
Asset retirement obligation, long-term	$ 1,936	$ 2,089

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 2022 and 2021, the Company recorded $4 million and $3 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 2022, net abandonment costs were revised downward approximately $148 million to reflect changes in estimates of timing, activity costs, and foreign currency exchange rates on service costs, primarily in the North Sea. This downward revision was partially offset by an upward revision in the U.S. During 2021, approximately $146 million net abandonment costs were revised upward to reflect changes in estimates of higher activity costs and long-term inflation assumptions, primarily in the U.S.

10. DEBT AND FINANCING COSTS

Overview

The debt of 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 the Company, including limits on Apache's ability to incur debt secured by certain liens. Certain of these indentures also restrict the Company's ability to enter into certain sale and leaseback transactions and give holders the option to require the Company 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.

On August 17, 2020, Apache closed offerings of $1.25 billion in aggregate principal amount of senior unsecured notes, comprised of $500 million in aggregate principal amount of 4.625% notes due 2025 and $750 million in aggregate principal amount of 4.875% notes due 2027. The senior unsecured notes are redeemable at any time, in whole or in part, at Apache's option, at the applicable redemption price. The net proceeds from the sale of the notes were used to purchase certain outstanding notes in cash tender offers, repay a portion of outstanding borrowings under Apache's former senior revolving credit facility, and for general corporate purposes.

On August 18, 2020, Apache closed cash tender offers for certain outstanding notes. Apache accepted for purchase $644 million aggregate principal amount of certain notes covered by the tender offers. Apache paid holders an aggregate cash purchase price of $644 million, reflecting principal, aggregate discount to par of $38 million, early tender premium of $32 million, and accrued and unpaid interest of $6 million. The Company recorded a net gain of $2 million on extinguishment of debt, including an acceleration of unamortized debt discount and issuance costs, in connection with the note purchases.

During 2020, Apache purchased in the open market and canceled senior notes issued under its indentures in an aggregate principal amount of $588 million for an aggregate purchase price of $428 million in cash, including accrued interest and broker fees, reflecting a discount to par of an aggregate $168 million. These repurchases resulted in a $158 million net gain on extinguishment of debt. The net gain includes an acceleration of related discount and debt issuance costs. Additionally, on November 3, 2020, Apache redeemed the remaining $183 million of outstanding 3.625% senior notes due February 1, 2021 at a redemption price equal to 100 percent of their principal amount, plus accrued and unpaid interest to the redemption date. The repurchases were financed by borrowings under Apache's former revolving credit facility.

During the quarter ended September 30, 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.

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 the quarter ended March 31, 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 the quarter ended March 31, 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 $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 U.S. dollar-denominated revolving credit facility of APA Corporation described below.

Apache intends to reduce debt outstanding under its indentures from time to time.

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, 2022 and 2021:

	December 31, 2022	December 31, 2021
	(In millions)	
3.25% notes due 2022[(1)]	$ —	$ 213
2.625% notes due 2023[(2)]	—	123
4.625% notes due 2025[(3)]	51	500
7.7% notes due 2026	78	79
7.95% notes due 2026	132	133
4.875% due 2027[(3)]	108	378
4.375% notes due 2028[(3)]	325	703
7.75% notes due 2029[(3)(4)]	235	235
4.25% notes due 2030[(3)]	579	580
6.0% notes due 2037[(3)]	443	443
5.1% notes due 2040[(3)]	1,333	1,333
5.25% notes due 2042[(3)]	399	399
4.75% notes due 2043[(3)]	428	428
4.25% notes due 2044[(3)]	221	221
7.375% debentures due 2047	150	150
5.35% notes due 2049[(3)]	387	387
7.625% debentures due 2096	39	39
Notes and debentures before unamortized discount and debt issuance costs[(5)]	4,908	6,344
Altus credit facility[(6)]	—	657
Syndicated credit facilities[(6)(7)]	—	542
Finance lease obligations	34	36
Unamortized discount	(27)	(30)
Debt issuance costs	(28)	(39)
Total debt	4,887	7,510
Current maturities	(2)	(215)
Long-term debt	$ 4,885	$ 7,295

(1) On January 18, 2022, Apache redeemed the 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.

(2) On October 17, 2022, Apache redeemed the 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.

(3) 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.

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

(5) The fair values of Apache's notes and debentures were $4.2 billion and $7.1 billion as of December 31, 2022 and 2021, 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).

(6) The carrying amount of borrowings on credit facilities approximates fair value because the interest rates are variable and reflective of market rates.

(7) Although Apache had no borrowings under APA's syndicated credit facilities as of December 31, 2022, Apache currently is a guarantor of obligations under those facilities.

Maturities for the Company's notes and debentures excluding discount and debt issuance costs as of December 31, 2022 are as follows:

	(In millions)
2023	$ —
2024	—
2025	51
2026	210
2027	108
Thereafter	4,539
Notes and debentures, excluding discounts and debt issuance costs	$ 4,908

Uncommitted Lines of Credit

The Company 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, 2022 and 2021, there were no outstanding borrowings under these facilities. As of December 31, 2022, there were £199 million and $17 million in letters of credit outstanding under these facilities. As of December 31, 2021, there were £117 million and $17 million in letters of credit outstanding under these facilities.

Unsecured Committed Bank Credit Facilities

On April 29, 2022, Apache entered into two unsecured guaranties of obligations under two unsecured syndicated credit agreements then entered into by APA Corporation (APA), of which Apache is a wholly owned subsidiary. APA's new credit agreements are for general corporate purposes and replaced and refinanced Apache's 2018 syndicated credit agreement (the Former Facility).

- One credit 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). APA 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 APA's two, one-year extension options.

- The second credit 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 APA's two, one-year extension options.

In connection with APA's entry into the USD Agreement and the GBP Agreement (each, a New Agreement), Apache terminated US$4.0 billion of commitments under the Former Facility, borrowings then outstanding under the Former Facility were deemed outstanding under APA's USD Agreement, and letters of credit then outstanding under the Former Facility were deemed outstanding under a New 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 New 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, 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. As of December 31, 2021, there were $542 million of borrowings and an aggregate £748 million and $20 million in letters of credit outstanding under the Former Facility. The letters of credit denominated in pounds were issued to support North Sea decommissioning obligations, the terms of which required such support after Standard & Poor's reduced Apache's credit rating from BBB to BB+ on March 26, 2020.

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 New 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, 2022, Apache's Long-Term Debt Rating applied, and the Base Rate Margin was 0.60%, the Applicable Margin was 1.60%, and the facility fee was 0.275%.

A commission is payable quarterly to lenders under each New 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 New 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, 2022, APA's debt-to-capital ratio as calculated under each New Agreement was 21 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 $1.5 billion as of December 31, 2022.

- 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 New 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.

Apache was in compliance with applicable terms of each New Agreement as of December 31, 2022.

In November 2018, Altus and its subsidiary, Altus Midstream LP (Altus LP), were subsidiaries of Apache, and Altus LP entered into an unsecured revolving credit facility for general corporate purposes. The agreement for the facility, as amended, provided aggregate commitments from a syndicate of banks of $800 million, including a letter of credit subfacility. The credit facility was not guaranteed by APA, Apache, or any of APA's other subsidiaries. On February 22, 2022, Altus was deconsolidated from APA and Apache. As of December 31, 2021, there were $657 million of borrowings and $2 million letters of credit outstanding under the facility.

Financing Costs, Net

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

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Interest expense	$ 312	$ 419	$ 438
Amortization of debt issuance costs	7	8	8
Capitalized interest	(1)	—	(12)
Loss (gain) on extinguishment of debt	67	104	(160)
Interest income	(9)	(8)	(7)
Interest income from APA Corporation, net	(63)	(51)	—
Financing costs, net	$ 313	$ 472	$ 267

As of December 31, 2022, the Company had $28 million of debt issuance costs, which will be charged to financing costs over the life of the related debt issuances. Discount amortization of $2 million, $6 million, and $7 million was recorded as interest expense in 2022, 2021, and 2020, respectively.

11. INCOME TAXES

Income (loss) before income taxes was composed of the following:

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
U.S.	$ 2,656	$ 689	$ (4,581)
Foreign	3,218	1,291	(259)
Total	$ 5,874	$ 1,980	$ (4,840)

The total income tax provision consisted of the following:

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Current income taxes:			
Federal	$ 1	$ 16	$ (2)
State	11	—	—
Foreign	1,495	636	178
	1,507	652	176
Deferred income taxes:			
Federal	—	—	—
Foreign	145	(74)	(112)
	145	(74)	(112)
Total	$ 1,652	$ 578	$ 64

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 income (loss) before income taxes and total tax expense is shown below:

	For the Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Income tax expense (benefit) at U.S. statutory rate	$ 1,234	$ 416	$ (1,016)
State income tax, less federal effect[1]	9	—	—
Taxes related to foreign operations	774	300	97
Tax credits	(4)	(10)	(13)
Net change in tax contingencies	1	16	1
Goodwill impairment	—	—	35
Valuation allowances[1]	(705)	(111)	965
Tax adjustments attributable to BCP Business Combination	126	—	—
Remeasurement of U.K. deferred tax liability	208	—	—
Tax attributable to Altus Preferred Unit limited partners	—	(34)	(16)
All other, net	9	1	11
	$ 1,652	$ 578	$ 64

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

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

	2022	2021
	(In millions)	
Deferred tax assets:		
U.S. and state net operating losses	$ 2,035	$ 2,494
Capital losses	357	647
Tax credits and other tax incentives	26	24
Foreign tax credits	2,241	2,241
Accrued expenses and liabilities	145	152
Asset retirement obligation	672	712
Property and equipment	—	3
Investment in Altus Midstream LP	—	64
Net interest expense limitation	55	135
Lease liability	113	81
Decommissioning contingency for sold Gulf of Mexico properties	275	263
Other	—	1
Total deferred tax assets	5,919	6,817
Valuation allowance	(4,831)	(5,875)
Net deferred tax assets	1,088	942
Deferred tax liabilities:		
Equity investments	1	2
Property and equipment	1,014	748
Right-of-use asset	110	77
Decommissioning security for sold Gulf of Mexico properties	148	164
Other	90	86
Total deferred tax liabilities	1,363	1,077
Net deferred income tax liability	$ 275	$ 135

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

	2022	2021
	(In millions)	
Assets:		
Deferred charges and other	$ 39	$ 13
Liabilities:		
Income taxes	314	148
Net deferred income tax liability	$ 275	$ 135

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 shares of Kinetik Class A Common Stock. 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 3— Acquisitions and Divestitures for further detail.

On May 26, 2022, the U.K. Chancellor of the Exchequer announced a new tax (the Energy Profits Levy) on the profits of oil and gas companies operating in the U.K. and the U.K. Continental Shelf. Under the new law, an additional levy is assessed at a 25 percent rate and is effective for the period of May 26, 2022, through December 31, 2025. The Company recorded a deferred tax expense of $208 million associated with the remeasurement of the U.K. deferred tax liability. On November 17, 2022, the U.K. Chancellor of the Exchequer announced in the Autumn Statement 2022 further changes to the Energy Profits Levy, increasing the levy assessed from a 25 percent rate to a 35 percent rate, effective for the period of January 1, 2023, through March 31, 2028. On November 22, 2022, the U.K. Government published draft legislation to implement this change, among other provisions, and on January 10, 2023, the Finance Act 2023 was enacted, receiving Royal Assent. Under U.S. GAAP, the financial statement impact of new legislation is recorded in the period of enactment. Therefore, in the first quarter of 2023, the Company expects to record a deferred tax expense of approximately $170 million to $190 million related to the remeasurement of the December 31, 2022 U.K. deferred tax liability.

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 (Corporate AMT) 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 Corporate AMT is effective for tax years beginning after December 31, 2022. The Company is continuing to evaluate the provisions of the IRA and awaits further guidance from the U.S. Treasury Department to properly assess the impact of these provisions on the Company.

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. A significant piece of negative evidence evaluated was the U.S. pre-tax book cumulative loss incurred over the three-year period ended December 31, 2022. This cumulative loss was primarily the result of low commodity prices and oil and gas impairments during this period. Such objective evidence limits the ability to consider other subjective evidence, such as the Company's projections for future growth.

However, given the Company's current and anticipated future domestic earnings, the Company believes that there is a reasonable possibility that within the next 12 months the U.S. will exit its cumulative loss, allowing the Company to reach a conclusion that a material portion of the U.S. valuation allowance may no longer be needed. A release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense, which could be material for the period the release is recorded.

In 2022, 2021, and 2020, the Company's valuation allowance decreased by $1.0 billion, decreased by $116 million, and increased by $1.0 billion, respectively, as detailed in the table below:

	2022	2021	2020
		(In millions)	
Balance at beginning of year	$ 5,875	$ 5,991	$ 4,959
State[(1)]	(111)	1	67
U.S.	(706)	(112)	960
Foreign	(227)	(5)	5
Balance at end of year	$ 4,831	$ 5,875	$ 5,991

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

On December 31, 2022, the Company had net operating losses as follows:

	Amount	Expiration
	(In millions)	
U.S.	$ 7,968	2027 - Indefinite
State	6,505	Various

The Company has a U.S. net operating loss carryforward of $8.0 billion, which includes $82 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 $6.5 billion, a net interest expense carryover of $246 million under Section 163(j) of the Code subject to indefinite carryover, and a U.S. capital loss carryforward of $1.6 billion, which has a five year carryover period expiring between 2023-2027. The Company has recorded a full valuation allowance against the U.S. net operating losses, the state net operating losses, the net interest expense carryover, and the U.S. capital loss because it is more likely than not that these attributes will not be realized.

On December 31, 2022, the Company had foreign tax credits as follows:

	Amount	Expiration
	(In millions)	
Foreign tax credits	$ 2,241	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:

	2022	2021	2020
		(In millions)	
Balance at beginning of year	$ 116	$ 93	$ 82
Additions based on tax positions related to prior year	—	16	—
Additions based on tax positions related to the current year	—	7	11
Reductions for tax positions of prior years	(27)	—	—
Balance at end of year	$ 89	$ 116	$ 93

The Company records interest and penalties related to unrecognized tax benefits as a component of income tax expense. Each quarter, the Company assesses the amounts provided for and, as a result, may increase or reduce the amount of interest and penalties. During each of the years ended December 31, 2022, 2021, and 2020, the Company recorded tax expense of $1 million for interest and penalties. At December 31, 2022, 2021, and 2020, the Company had an accrued liability for interest and penalties of $5 million, $4 million, and $3 million, respectively.

In 2022, 2021, and 2020, the Company recorded a $27 million net decrease, a $23 million net increase, and an $11 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.

Apache 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. Apache's earliest open tax years in its key jurisdictions are as follows:

Jurisdiction	
U.S.	2014
Egypt	2005
U.K.	2021

12. 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, 2022, the Company has an accrued liability of approximately $64 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. For material matters that 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 2022, 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. While adverse judgments against the Company might be possible, the Company intends to vigorously oppose these claims.

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 plaintiff's claims. The Texas Supreme Court granted the Company's petition for review and heard oral argument in October 2022.

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 believes that Quadrant's claims lack merit and will not have a material adverse effect on the Company's financial position, results of operation, or liquidity.

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. The Company believes that plaintiffs' claims lack merit and will not have a material adverse effect on the Company's financial position, results of operation, or liquidity.

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 November 14, 2018, the Pacific Coast Federation of Fishermen's Associations, Inc. also filed a similar lawsuit against many of the same defendants. After removal of all such lawsuits to federal court, the district court remanded them back to state court. The 9th Circuit Court of Appeals' affirmance of this remand decision was appealed to the U.S. Supreme Court. That appeal was decided by the U.S. Supreme Court ruling in a similar case, *BP p.l.c. v. Mayor and City Council of Baltimore*. As a result, the California cases were sent back to the 9th Circuit for further appellate review of the decision to remand the cases to state court. The 9th Circuit has since, once again, affirmed the district court's remand to state court. The defendants are appealing this latest remand decision to the U.S. Supreme Court.

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. After removal of this lawsuit to federal court, the district court remanded it back to state court. The 3rd Circuit has since, once again, affirmed the district court's remand to state court. The defendants are appealing this latest remand decision to the U.S. Supreme Court.

The Company believes that it is not subject to jurisdiction of the California courts and that claims made against it in the California and Delaware litigation are baseless. The Company intends to challenge jurisdiction in California and to vigorously defend the Delaware lawsuit.

Castex Lawsuit

In a case styled *Apache Corporation v. Castex Offshore, Inc., et. al.*, Cause No. 2015-48580, in the 113th Judicial District Court of Harris County, Texas, Castex filed claims for alleged damages of approximately $200 million, relating to overspend on the Belle Isle Gas Facility upgrade, and the drilling of five sidetracks on the Potomac #3 well. After a jury trial, a verdict of approximately $60 million, plus fees, costs, and interest was entered against the Company. The Fourteenth Court of Appeals of Texas reversed the judgment, in part, reducing the judgment to approximately $13.5 million, plus fees, costs, and interest against the Company. Further appeal is pending.

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 believes that plaintiffs' claims lack merit and intends to vigorously defend this lawsuit.

On January 18, 2023, a case captioned *Jerry Hight, Derivatively and on behalf of APA Corporation v. John J. Christmann IV et al.* was filed in the 61st District Court of Harris County, Texas. The case purports to be a derivative action 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 believe that plaintiff's claims lack merit and intend to vigorously defend this lawsuit.

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, 2022, the Company had an undiscounted reserve for environmental remediation of approximately $1 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. The notice and information request involve alleged emissions control and reporting violations. The Company is cooperating with the EPA and has responded to the information request. The EPA has referred the notice for civil enforcement proceedings; however, at this time the Company is unable to reasonably estimate whether such proceedings will result in monetary sanctions and, if so, whether they would be more or less than $100,000, exclusive of interest and costs.

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 notice and information request involve alleged emissions control and reporting violations. The Company is cooperating with the EPA and has responded to the information request. The EPA has referred the notice for civil enforcement proceedings; however, at this time the Company is unable to reasonably estimate whether such proceedings will result in monetary sanctions and, if so, whether they would be more or less than $100,000, exclusive of interest and costs.

The Company is not aware of any environmental claims existing as of December 31, 2022 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. Currently, Apache holds two bonds (Bonds) and five Letters of Credit to secure 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 decommissioning of Legacy GOM Assets.

By letter dated April 5, 2022, replacing two prior letters dated September 8, 2021 and February 22, 2022, 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 notification to BSEE. Apache expects to receive such orders on the other Legacy GOM Assets included in GOM Shelf's notification letter. 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.

If Apache incurs costs to decommission any Legacy GOM Asset and GOM Shelf does not reimburse Apache for such costs, then Apache expects to obtain reimbursement from Trust A, the Bonds, and the Letters of Credit until 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 ordered by BSEE to perform, 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 effectively use its available cash to fund the deficit.

As of December 31, 2022, Apache estimates that its potential liability to fund decommissioning of Legacy GOM Assets it may be ordered to perform ranges from $1.2 billion to $1.4 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 $1.2 billion as of December 31, 2022, representing the estimated costs of decommissioning it may be required to perform on Legacy GOM Assets. Of the total liability recorded, $738 million is reflected under the caption "Decommissioning contingency for sold Gulf of Mexico properties," and $450 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, 2022, the Company has also recorded a $667 million asset, which represents the 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, $217 million is reflected under the caption "Decommissioning security for sold Gulf of Mexico properties," and $450 million is reflected under "Other current assets." The Company recognized $157 million and $446 million during 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.

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, Apache 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, Apache 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. As allowed under ASU 2016-02, "Leases (Topic 842)," the Company applied practical expedients permitting an entity the option to not evaluate under such standard those existing or expired land easements that were not previously accounted for as leases as well as permitting an entity the option to carry forward its historical assessments of whether existing agreements contain a lease, classification of existing lease agreements, and treatment of initial direct lease costs.

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 $144 million, $127 million, and $149 million for the years ended 2022, 2021, and 2020, respectively. As allowed under the standard, Apache elected to exclude short-term leases (those with terms of 12 months or less) from the balance sheet presentation.

In addition, the Company periodically enters into finance leases that are similar to those leases classified as capital leases under previous GAAP. 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 2022, 2021, and 2020. Interest on the Company's finance lease liability was $2 million in each of the years 2022, 2021, and 2020.

The following table represents the Company's weighted average lease term and discount rate as of December 31, 2022:

	Operating Leases	Finance Lease
Weighted average remaining lease term	2.5 years	10.7 years
Weighted average discount rate	3.7 %	4.4 %

At December 31, 2022, 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)	
2023	$ 174	$ 3	$ 222
2024	102	3	183
2025	14	4	163
2026	6	4	1,951
2027	6	4	133
Thereafter	11	27	333
Total future minimum payments	313	45	$ 2,985
Less: imputed interest	(14)	(11)	N/A
Total lease liabilities	299	34	N/A
Current portion	167	2	N/A
Non-current portion	$ 132	$ 32	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 $183 million, $194 million, and $120 million in 2022, 2021, and 2020, respectively.

(5) Under terms agreed to in the new Egypt merged concession agreement, 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, 2022, the Company has spent $1.7 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 $89 million, $63 million, and $41 million in 2022, 2021, and 2020, respectively.

In addition to the lease liabilities in the table above, at December 31, 2022, undiscounted fixed minimum payments for operating leases not yet commenced totaled $207 million. The leases primarily relate to office leases in Houston and Egypt, and estimated cash payments for 2023 are not expected to be material. The underlying assets for these leases were primarily designed by the lessors, and the Company is in the process of designing leasehold improvements for both leases.

13. 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 to the plan up to 50 percent of eligible compensation as defined in 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 qualifying change in control of ownership of APA Corporation, as defined in the applicable plan, 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 $40 million, $31 million, and $43 million for 2022, 2021, and 2020, 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, 2022, 2021, and 2020, 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.

	2022		2021		2020	
	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	$ 211	$ 20	$ 233	$ 20	$ 199	$ 20
Service cost	2	1	3	1	3	1
Interest cost	3	—	3	—	4	—
Foreign currency exchange rates	(21)	—	(2)	—	8	—
Actuarial losses (gains)	(79)	(5)	(5)	1	30	1
Plan settlements	—	—	(17)	—	—	—
Benefits paid	(8)	(3)	(4)	(4)	(11)	(4)
Retiree contributions	—	2	—	2	—	2
Projected benefit obligation at end of year	108	15	211	20	233	20
Change in Plan Assets						
Fair value of plan assets at beginning of year	254	—	262	—	228	—
Actual return (loss) on plan assets	(87)	—	11	—	31	—
Foreign currency exchange rates	(26)	—	(3)	—	9	—
Employer contributions	4	2	5	2	5	2
Plan settlements	—	—	(17)	—	—	—
Benefits paid	(8)	(4)	(4)	(4)	(11)	(4)
Retiree contributions	—	2	—	2	—	2
Fair value of plan assets at end of year	137	—	254	—	262	—
Funded status at end of year	$ 29	$ (15)	$ 43	$ (20)	$ 29	$ (20)
Amounts recognized in Consolidated Balance Sheet						
Current liability	$ —	$ (2)	$ —	$ (2)	$ —	$ (2)
Non-current asset (liability)	29	(13)	43	(18)	29	(18)
	$ 29	$ (15)	$ 43	$ (20)	$ 29	$ (20)
Pre-tax Amounts Recognized in Accumulated Other Comprehensive Income (Loss)						
Accumulated gain (loss)	$ (10)	$ 18	$ 1	$ 14	$ (11)	$ 16
Weighted Average Assumptions used as of 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 2028	N/A	5.25 %	N/A	5.00 %	N/A	5.00 %

As of December 31, 2022, 2021, and 2020, the accumulated benefit obligation for the U.K. Pension Plan was $89 million, $205 million, and $207 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 in a blend of equity securities and low-risk debt securities. The Company intends that this blend of investments will provide a reasonable rate of return such that the benefits promised to members are provided. 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 previous allocations for plan asset holdings and the target allocation for the Company's plan assets are summarized below:

	Target Allocation	Percentage of Plan Assets at Year-End	
	2022	2022	2021
Asset Category			
Equity securities:			
Overseas quoted equities	14 %	15 %	15 %
Total equity securities	14 %	15 %	15 %
Debt securities:			
U.K. government bonds	52 %	52 %	54 %
U.K. corporate bonds	32 %	32 %	25 %
Total debt securities	84 %	84 %	79 %
Cash	2 %	1 %	6 %
Total	100 %	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, 2022 and 2021 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, 2022 and 2021:

	December 31,	
	2022	2021
	(In millions)	
Equity securities:		
Overseas quoted equities	$ 20	$ 38
Total equity securities	20	38
Debt securities:		
U.K. government bonds	71	138
U.K. corporate bonds	44	62
Total debt securities	115	200
Cash	2	16
Fair value of plan assets	$ 137	$ 254

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, 2022, 2021, and 2020:

	2022		2021		2020	
	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits	Pension Benefits	Postretirement Benefits
	(In millions)					
Components of Net Periodic Benefit Cost						
Service cost	$ 2	$ 1	$ 3	$ 1	$ 3	$ 1
Interest cost	3	—	3	—	4	—
Expected return on assets	(4)	—	(4)	—	(5)	—
Amortization of loss	—	(1)	—	(1)	—	(1)
Settlement loss	—	—	—	—	—	—
Net periodic benefit cost	$ 1	$ —	$ 2	$ —	$ 2	$ —
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost for the Years Ended December 31						
Discount rate	1.80 %	2.57 %	1.40 %	2.06 %	2.10 %	3.00 %
Salary increases	4.90 %	N/A	4.50 %	N/A	4.30 %	N/A
Expected return on assets	1.90 %	N/A	1.50 %	N/A	2.20 %	N/A
Healthcare cost trend						
Initial	N/A	6.25 %	N/A	6.00 %	N/A	6.25 %
Ultimate in 2028	N/A	5.00 %	N/A	5.00 %	N/A	5.00 %

The Company expects to contribute approximately $2 million to its pension plan and $3 million to its postretirement benefit plan in 2023. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Postretirement Benefits
	(In millions)	
2023	$ 5	$ 2
2024	5	2
2025	5	2
2026	5	1
2027	5	1
Years 2028-2032	28	6

14. 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 (the Closing). 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. Pursuant to this method, the net transaction price was accreted using the effective interest method to the Redemption Price calculated at the seventh anniversary of the Closing. The total adjustment was limited to an amount such that the carrying amount of the Preferred Unit redeemable noncontrolling interest at each period end was equal to the greater of (a) the sum of (i) the carrying amount of the Preferred Units, plus (ii) the fair value of the embedded derivative liability and (b) the accreted value of the net transaction price.

Activity related to the Preferred Units for the 2022 and 2021 periods is as follows:

	Units Outstanding	Financial Position(1)
	(In millions, except unit data)	
Redeemable noncontrolling interest — Altus Preferred Unit limited partners: at December 31, 2020	660,694	$ 608
Cash distributions to Altus Preferred Unit limited partners	—	(46)
Distributions payable to Altus Preferred Unit limited partners	—	(12)
Allocation of Altus Midstream net income	N/A	80
Accreted value adjustment	N/A	82
Redeemable noncontrolling interest — Altus Preferred Unit limited partners: at December 31, 2021	660,694	712
Allocation of Altus Midstream LP net income	N/A	12
Accreted value adjustment(1)	N/A	(82)
Redeemable noncontrolling interest — Altus Preferred Unit limited partners: at February 22, 2022	660,694	642
Preferred Units embedded derivative		89
Deconsolidation of Altus		(731)
		$ —

(1) Includes the reversal of previously recorded accreted value adjustments due to the deconsolidation of Altus.

N/A - not applicable.

15. CAPITAL STOCK AND EQUITY

Upon consummation of the Holding Company Reorganization, each outstanding share of Apache common stock automatically converted into a share of APA common stock on a one-for-one basis. As a result, each stockholder of Apache now owns the same number of shares of APA common stock that such stockholder owned of Apache common stock immediately prior to the Holding Company Reorganization. As a result of the Holding Company Reorganization and subsequent activity, Apache recorded various intercompany activities during the quarter ended March 31, 2021 as capital transactions, which are reflected in Apache's Statement of Consolidated Changes in Equity (Deficit) and Noncontrolling Interest. Refer to Note 2—Transactions with Parent Affiliate for more detail.

Additionally, in connection with the Holding Company Reorganization, Apache transferred to APA, and APA assumed, sponsorship of all of Apache's stock plans along with all of Apache's rights and obligations under each plan. Subsequent to the Holding Company Reorganization, stock-based compensation associated with APA equity awards granted and outstanding to Apache employees are reflected as capital contributions from APA to Apache.

Net Income (Loss) per Common Share

Net income (loss) per share for Apache is no longer required, as its shares are not publicly traded, and Apache is now a direct, wholly owned subsidiary of APA.

Stock Compensation Plans

Prior to consummation of the Holding Company Reorganization, the Company maintained 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, 2022, 10.1 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 Year Ended December 31,		
	2022	2021	2020
		(In millions)	
Stock-settled and cash-settled compensation expensed	$ 288	$ 152	$ 40
Stock-settled and cash-settled compensation capitalized	43	18	7
Total stock-settled and cash-settled compensation costs	$ 331	$ 170	$ 47

Stock Options

As of December 31, 2022, APA had outstanding options to purchase shares of APA's 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, 2022, 2021, and 2020:

	2022		2021		2020	
	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	3,012	$ 63.79	3,537	$ 72.10	4,298	$ 75.24
Exercised	(99)	42.09	—	—	—	—
Forfeited	(2)	49.10	—	—	(37)	44.98
Expired	(833)	81.56	(525)	119.83	(724)	92.14
Outstanding, end of year[1]	2,078	57.71	3,012	63.79	3,537	72.10
Expected to vest	—	—	—	—	150	45.77
Exercisable, end of year[1]	2,078	57.71	3,012	63.79	3,387	73.26

(1) As of December 31, 2022, options exercisable and outstanding had a weighted average remaining contractual life of 3.1 years and aggregate intrinsic value of $3.5 million.

There were no options issued and 98,646 options exercised during the year ended December 31, 2022. There were no options issued and no options exercised during the years ended December 31, 2021, and 2020.

Restricted Stock Units and Restricted Stock Phantom Units

Prior to consummation of the Holding Company Reorganization, the Company had 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 APA'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, 2022, 2021, and 2020, compensation costs charged to expense for the restricted stock units and restricted stock phantom units was $145 million, $91 million, and $39 million, respectively. As of December 31, 2022, 2021, and 2020, capitalized compensation costs for the restricted stock units and restricted stock phantom units were $22 million, $15 million, and $6 million, respectively.

The following table summarizes stock-settled restricted stock unit activity for the years ended December 31, 2022, 2021, and 2020:

	2022		2021		2020	
	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	2,073	$ 19.98	1,552	$ 28.43	2,448	$ 46.65
Granted	847	29.90	1,506	16.46	1,352	24.60
Vested[3]	(978)	22.39	(857)	29.13	(1,933)	48.65
Forfeited	(57)	23.49	(128)	19.78	(315)	30.09
Non-vested, end of year[1][2]	1,885	23.08	2,073	19.98	1,552	28.43

(1) As of December 31, 2022, there was $14 million of total unrecognized compensation cost related to 1,885,491 unvested stock-settled restricted stock units.

(2) As of December 31, 2022, the weighted-average remaining life of unvested stock-settled restricted stock units is approximately 0.7 years.

(3) The grant date fair values of the stock-settled awards vested during 2022, 2021, and 2020 were approximately $22 million, $25 million, and $94 million, respectively.

The following table summarizes cash-settled restricted stock phantom unit activity for the years ended December 31, 2022, 2021, and 2020:

	For the Year Ended December 31,		
	2022	2021	2020
	(In thousands)		
Non-vested, beginning of year	6,402	4,423	5,384
Adjustment for ALTM reverse stock split[(1)]	—	—	(1,246)
Adjustment from ALTM transaction[(2)]	143	—	—
Granted[(3)]	2,568	4,441	3,462
Vested	(2,970)	(2,049)	(1,618)
Forfeited	(434)	(413)	(1,559)
Non-vested, end of year[(4)]	5,709	6,402	4,423

(1) Prior to the deconsolidation of Altus on February 22, 2022, on June 30, 2020, ALTM executed a 1-for-20 reverse stock split of its outstanding common stock. Outstanding cash-settled awards were based on the per-share market price of ALTM common stock.

(2) 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.

(3) Restricted stock phantom units granted during 2022, 2021, and 2020 included 2,512,602, 4,375,546, and 3,378,486 awards, respectively, based on the per-share market price of APA common stock and 55,546, 65,327, and 83,239 awards, respectively, based on the per-share market price of ALTM common stock prior to the deconsolidation of Altus on February 22, 2022. The restricted stock phantom units granted during 2020 based on ALTM's per-share market price reflect the 1-for-20 reverse stock split described above.

(4) The outstanding liability for the unvested cash-settled restricted stock phantom units that had not been recognized as of December 31, 2022 was approximately $103 million.

In January 2023, APA awarded 580,254 restricted stock units and 1,950,332 restricted stock phantom units based on APA's weighted-average per-share market price of $42.15 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 $24 million and $85 million, respectively, and was calculated based on the per-share fair market value of a share of APA'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 conditional restricted stock units to eligible employees. Apache 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, 2022, are as described below:

- In January 2018, the Company's Board of Directors approved the 2018 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial cash-settled conditional phantom units totaling 931,049 units. A total of 23,633 phantom units were outstanding as of December 31, 2022. The results for the performance period yielded a payout of 23 percent of target.
- In January 2019, the Company's Board of Directors approved the 2019 Performance Program, pursuant to the 2016 Plan. Eligible employees received initial cash-settled conditional phantom units totaling 1,679,832 units. A total of 604,417 phantom units were outstanding as of December 31, 2022. The results for the performance period yielded a payout of 100 percent of target.
- 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 1,311,715 phantom units were outstanding as of December 31, 2022. 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. The actual amount of phantom units awarded will be between zero and 200 percent of target. A total of 1,826,890 phantom units were outstanding as of December 31, 2022, from which a minimum of zero to a maximum of 3,653,780 units could be awarded.
- 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 amount of phantom units awarded will be between zero and 200 percent of target. A total of 1,068,530 phantom units were outstanding as of December 31, 2022, from which a minimum of zero to a maximum of 2,137,060 units could be awarded.

Compensation costs charged to expense under the performance programs were an expense of $136 million, an expense of $56 million, and a credit of $8 million during 2022, 2021, and 2020, respectively. Capitalized compensation costs under the performance programs were an expense of $21 million, an expense of $3 million, and a credit of $1 million during 2022, 2021, and 2020, respectively.

The following table summarizes cash-settled conditional restricted stock unit activity for the year ended December 31, 2022:

	Units (In thousands)
Non-vested, beginning of year	4,531
Granted	1,676
Vested	(656)
Forfeited	(106)
Expired	(610)
Non-vested, end of year[(1)]	4,835

(1) As of December 31, 2022, the outstanding liability for the unvested cash-settled conditional restricted stock units that had not been recognized was approximately $53 million.

In January 2023, APA's board of directors approved the 2023 Performance Program, pursuant to the 2016 Plan. Payout for 40 percent of the shares is based upon measurement of TSR of APA common stock as compared to a designated peer group and the S&P 500 Index during a three-year performance period. Payout for the remaining 60 percent of the shares is based on the performance and financial objectives defined in the 2023 Performance Program. Eligible employees received the initial cash-settled conditional phantom units totaling 797,429 units, with the ultimate number of phantom units to be awarded ranging from zero to a maximum of 1,594,858 units. These phantom units represent a hypothetical interest in the Company's common stock, and, once vested, are settled in cash. The TSR component of the award had a grant date fair value per award of $62.15 based on a Monte Carlo simulation. The grant date fair value per award for the remaining 60 percent was $44.06 based on the weighted-average fair market value of a share of common stock of APA as of the grant date. These 2023 Performance Program 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.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Components of accumulated other comprehensive income (loss) include the following:

	As of December 31, 2022	2021	2020
	(In millions)		
Share of equity method interests other comprehensive loss	$ —	$ —	$ (1)
Pension and postretirement benefit plan (Note 13)	14	22	15
Accumulated other comprehensive income	$ 14	$ 22	$ 14

17. 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 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. During 2020, sales to EGPC and Vitol accounted for approximately 17 percent and 14 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.

18. BUSINESS SEGMENT INFORMATION

As of December 31, 2022, the Company is 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 natural gas, crude oil and NGLs. Prior to the deconsolidation of Altus on February 22, 2022, the Company’s midstream business was operated by Altus, which owned, developed, and operated a midstream energy asset network in the Permian Basin of West Texas. Financial information for each segment is presented below:

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
	(In millions)					
2022						
Oil revenues	$ 3,145	$ 1,232	$ 2,323	$ —	$ —	$ 6,700
Natural gas revenues	370	281	894	—	—	1,545
Natural gas liquids revenues	6	45	735	—	(3)	783
Oil, natural gas, and natural gas liquids production revenues	3,521	1,558	3,952	—	(3)	9,028
Purchased oil and gas sales	—	—	1,850	5	—	1,855
Midstream service affiliate revenues	—	—	—	16	(16)	—
	3,521	1,558	5,802	21	(19)	10,883
Operating Expenses:						
Lease operating expenses	526	404	506	—	(1)	1,435
Gathering, processing, and transmission	22	43	304	5	(18)	356
Purchased oil and gas costs	—	—	1,776	—	—	1,776
Taxes other than income	—	—	253	3	—	256
Exploration	84	35	24	—	3	146
Depreciation, depletion, and amortization	400	238	537	2	—	1,177
Asset retirement obligation accretion	—	82	34	1	—	117
	1,032	802	3,434	11	(16)	5,263
Operating Income (Loss)	$ 2,489	$ 756	$ 2,368	$ 10	$ (3)	5,620
Other Income (Expense):						
Gain on divestitures, net						1,180
Losses on previously sold Gulf of Mexico properties						(157)
Derivative instrument losses, net						(107)
Other						139
General and administrative						(462)
Transaction, reorganization, and separation						(26)
Financing costs, net						(313)
Income Before Income Taxes						$ 5,874
Total Assets[3]	$ 3,148	$ 1,911	$ 9,196	$ —	$ —	$ 14,255
Net Property and Equipment	$ 1,976	$ 1,386	$ 4,595	$ —	$ —	$ 7,957
Additions to Net Property and Equipment	$ 695	$ 210	$ 752	$ —	$ —	$ 1,657

	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	63	34	28	—	2	127
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	(128)	5,097
Operating Income (Loss)	$ 991	$ 309	$ 1,679	$ (89)	$ (2)	2,888
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						(357)
Transaction, reorganization, and separation						(22)
Financing costs, net						(472)
Income Before Income Taxes						$ 1,980
Total Assets[3]	$ 2,796	$ 2,199	$ 7,700	$ 1,698	$ —	$ 14,393
Net Property and Equipment	$ 1,720	$ 1,646	$ 4,507	$ 187	$ —	$ 8,060
Additions to Net Property and Equipment	$ 319	$ 159	$ 523	$ 3	$ —	$ 1,004

	Egypt[1]	North Sea	U.S.	Altus Midstream	Intersegment Eliminations & Other	Total[2]
	Upstream					
	(In millions)					
2020						
Oil revenues	$ 1,102	$ 795	$ 1,209	$ —	$ —	$ 3,106
Natural gas revenues	280	67	251	—	—	598
Natural gas liquids revenues	8	21	304	—	—	333
Oil, natural gas, and natural gas liquids production revenues	1,390	883	1,764	—	—	4,037
Purchased oil and gas sales	—	—	394	4	—	398
Midstream service affiliate revenues	—	—	—	145	(145)	—
	1,390	883	2,158	149	(145)	4,435
Operating Expenses:						
Lease operating expenses	424	305	400	—	(2)	1,127
Gathering, processing, and transmission	38	50	291	38	(143)	274
Purchased oil and gas costs	—	—	354	3	—	357
Taxes other than income	—	—	108	15	—	123
Exploration	63	28	168	—	15	274
Depreciation, depletion, and amortization	601	380	779	12	—	1,772
Asset retirement obligation accretion	—	73	32	4	—	109
Impairments	529	7	3,963	2	—	4,501
	1,655	843	6,095	74	(130)	8,537
Operating Income (Loss)	$ (265)	$ 40	$ (3,937)	$ 75	$ (15)	(4,102)
Other Income (Expense):						
Gain on divestitures, net						32
Derivative instrument losses, net						(223)
Other						64
General and administrative						(290)
Transaction, reorganization, and separation						(54)
Financing costs, net						(267)
Loss Before Income Taxes						$ (4,840)
Total Assets[3]	$ 3,003	$ 2,220	$ 5,540	$ 1,786	$ 197	$ 12,746
Net Property and Equipment	$ 1,955	$ 1,773	$ 4,760	$ 196	$ 135	$ 8,819
Additions to Net Property and Equipment	$ 454	$ 215	$ 345	$ 12	$ 136	$ 1,162

(1) Includes revenue from non-customers for the years ended December 31, 2022, 2021, and 2020 of:

	For the Year Ended December 31, 2022	2021	2020
	(In millions)		
Oil	$ 989	$ 420	$ 95
Natural gas	117	47	14
Natural gas liquids	2	2	—

(2) Includes noncontrolling interests in Egypt and Altus Midstream.

(3) Intercompany balances are excluded from total assets.

19. 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. Apache 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)		
2022					
Oil and gas production revenues	$ 3,952	$ 3,521	$ 1,558	$ —	$ 9,031
Operating cost:					
Depreciation, depletion, and amortization[2]	508	390	232	—	1,130
Asset retirement obligation accretion	34	—	82	—	116
Lease operating expenses	506	526	404	—	1,436
Gathering, processing, and transmission	304	22	43	—	369
Exploration expenses	24	84	35	3	146
Production taxes[3]	252	—	—	—	252
Income tax	488	1,100	495	—	2,083
	2,116	2,122	1,291	3	5,532
Results of operations	$ 1,836	$ 1,399	$ 267	$ (3)	$ 3,499
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	2	127
Production taxes[3]	188	—	—	—	188
Income tax	383	479	134	—	996
	1,840	1,500	936	2	4,278
Results of operations	$ 1,440	$ 585	$ 200	$ (2)	$ 2,223
2020					
Oil and gas production revenues	$ 1,764	$ 1,390	$ 883	$ —	$ 4,037
Operating cost:					
Depreciation, depletion, and amortization[2]	726	540	377	—	1,643
Asset retirement obligation accretion	32	—	73	—	105
Lease operating expenses	400	424	305	—	1,129
Gathering, processing, and transmission	291	38	50	—	379
Exploration expenses	168	63	28	15	274
Impairments related to oil and gas properties	3,938	374	7	—	4,319
Production taxes[3]	106	—	—	—	106
Income tax	(818)	(22)	17	—	(823)
	4,843	1,417	857	15	7,132
Results of operations	$ (3,079)	$ (27)	$ 26	$ (15)	$ (3,095)

(1) Includes noncontrolling interests 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 18—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 18—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)		
2022					
Acquisitions:					
Proved	$ 19	$ 3	$ —	$ —	$ 22
Unproved	28	—	—	—	28
Exploration	4	169	61	3	237
Development	775	568	(57)	—	1,286
Costs incurred[(1)]	$ 826	$ 740	$ 4	$ 3	$ 1,573
[(1)] Includes capitalized interest, asset retirement costs:					
Capitalized interest	$ —	$ —	$ 1	$ —	$ 1
Asset retirement costs	76	—	(215)	—	(139)
2021					
Acquisitions:					
Proved	$ —	$ (157)	$ —	$ —	$ (157)
Unproved	9	20	—	—	29
Exploration	6	86	39	30	161
Development	545	404	135	1	1,085
Costs incurred[(1)]	$ 560	$ 353	$ 174	$ 31	$ 1,118
[(1)] Includes capitalized interest and asset retirement costs, and Egypt modernization impacts as follows:					
Capitalized interest	$ —	$ —	$ —	$ —	$ —
Asset retirement costs	130	—	19	—	149
Egypt PSC modernization impacts - Proved and Unproved	—	(145)	—	—	(145)
2020					
Acquisitions:					
Proved	$ —	$ 7	$ —	$ —	$ 7
Unproved	4	—	—	—	4
Exploration	8	102	68	150	328
Development	332	378	162	—	872
Costs incurred[(1)]	$ 344	$ 487	$ 230	$ 150	$ 1,211
[(1)] Includes capitalized interest and asset retirement costs as follows:					
Capitalized interest	$ —	$ —	$ —	$ 3	$ 3
Asset retirement costs	9	—	29	—	38

[(2)] Includes a noncontrolling interest in Egypt.

In 2021, in connection with Apache's agreement to enter into a new merged concession agreement with EGPC, as referenced in Note 1—Summary of Significant Accounting Policies, 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)		
2022					
Proved properties	$ 18,990	$ 13,014	$ 8,945	$ —	$ 40,949
Unproved properties	208	77	11	—	296
	19,198	13,091	8,956	—	41,245
Accumulated DD&A	(14,846)	(11,157)	(7,573)	—	(33,576)
	$ 4,352	$ 1,934	$ 1,383	$ —	$ 7,669
2021					
Proved properties	$ 18,732	$ 12,373	$ 8,954	$ —	$ 40,059
Unproved properties	319	63	33	—	415
	19,051	12,436	8,987	—	40,474
Accumulated DD&A	(14,814)	(10,767)	(7,345)	—	(32,926)
	$ 4,237	$ 1,669	$ 1,642	$ —	$ 7,548

(1) Includes noncontrolling interests 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, Apache 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. Apache 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, 2019	278,145	103,573	101,712	483,430
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	168,817	108,050	82,580	359,447
Proved undeveloped reserves:				
December 31, 2019	46,716	10,831	10,049	67,596
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	16,221	8,557	2,873	27,651
Total proved reserves:				
Balance December 31, 2019	324,861	114,404	111,761	551,026
Extensions, discoveries and other additions	17,858	17,855	5,275	40,988
Revisions of previous estimates	(69,247)	2,541	(4,756)	(71,462)
Production	(32,299)	(27,591)	(18,441)	(78,331)
Sales of minerals in-place	(8,721)	—	—	(8,721)
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	522	—	—	522
Revisions of previous estimates	7,170	22,433	11,898	41,501
Production	(24,141)	(31,055)	(11,891)	(67,087)
Sales of minerals in-place	(7,425)	—	—	(7,425)
Balance December 31, 2022	185,038	116,607	85,453	387,098

(1) Includes proved reserves of 62 MMbbls, 39 MMbbls, 36 MMbbls, and 38 MMbbls as of December 31, 2022, 2021, 2020, and 2019, respectively, attributable to noncontrolling interests in Egypt.

	Natural Gas Liquids			
	United States	Egypt[1]	North Sea	Total[1]
	(Thousands of barrels)			
Proved developed reserves:				
December 31, 2019	158,794	667	2,317	161,778
December 31, 2020	150,599	716	2,053	153,368
December 31, 2021	164,172	446	2,059	166,677
December 31, 2022	152,999	—	2,230	155,229
Proved undeveloped reserves:				
December 31, 2019	23,569	90	660	24,319
December 31, 2020	15,141	126	320	15,587
December 31, 2021	16,380	30	275	16,685
December 31, 2022	15,398	—	76	15,474
Total proved reserves:				
Balance December 31, 2019	182,363	757	2,977	186,097
Extensions, discoveries and other additions	11,435	97	312	11,844
Revisions of previous estimates	(469)	264	(207)	(412)
Production	(27,133)	(276)	(709)	(28,118)
Sales of minerals in-place	(456)	—	—	(456)
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	233	—	—	233
Revisions of previous estimates	10,355	(407)	333	10,281
Production	(21,859)	(69)	(406)	(22,334)
Sales of minerals in-place	(6,340)	—	—	(6,340)
Balance December 31, 2022	168,397	—	2,306	170,703

(1) Includes proved reserves of 159 Mbbls, 281 Mbbls, and 252 Mbbls as of December 31, 2021, 2020, and 2019, respectively, attributable to noncontrolling interests in Egypt.

	Natural Gas			
	United States	Egypt[(1)]	North Sea	Total[(1)]
	(Millions of cubic feet)			
Proved developed reserves:				
December 31, 2019	945,938	433,382	106,329	1,485,649
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	1,128,066	399,502	66,292	1,593,860
Proved undeveloped reserves:				
December 31, 2019	115,040	24,704	16,604	156,348
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	188,976	1,068	2,304	192,348
Total proved reserves:				
Balance December 31, 2019	1,060,978	458,086	122,933	1,641,997
Extensions, discoveries and other additions	60,965	83,718	8,140	152,823
Revisions of previous estimates	215,166	(19,849)	(33,541)	161,776
Production	(205,594)	(100,348)	(21,032)	(326,974)
Sales of minerals in-place	(2,255)	—	—	(2,255)
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	1,592	—	—	1,592
Revisions of previous estimates	96,381	45,725	(3,431)	138,675
Production	(167,580)	(130,071)	(12,895)	(310,546)
Sales of minerals in-place	(73,410)	—	—	(73,410)
Balance December 31, 2022	1,317,042	400,570	68,596	1,786,208

(1) Includes proved reserves of 224 Bcf, 158 Bcf, 141 Bcf, and 153 Bcf as of December 31, 2022, 2021, 2020, and 2019, respectively, attributable to noncontrolling interests in Egypt.

	Total Equivalent Reserves			
	United States	Egypt[(1)]	North Sea	Total[(1)]
	(Thousands barrels of oil equivalent)			
Proved developed reserves:				
December 31, 2019	594,595	176,470	121,751	892,816
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	509,827	174,633	95,859	780,319
Proved undeveloped reserves:				
December 31, 2019	89,458	15,038	13,476	117,972
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	63,115	8,735	3,333	75,183
Total proved reserves:				
Balance December 31, 2019	684,053	191,508	135,227	1,010,788
Extensions, discoveries and other additions	39,454	31,905	6,944	78,303
Revisions of previous estimates	(33,854)	(502)	(10,554)	(44,910)
Production	(93,698)	(44,592)	(22,655)	(160,945)
Sales of minerals in-place	(9,553)	—	—	(9,553)
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	1,020	—	—	1,020
Revisions of previous estimates	33,588	29,647	11,659	74,894
Production	(73,930)	(52,803)	(14,446)	(141,179)
Sales of minerals in-place	(26,000)	—	—	(26,000)
Balance December 31, 2022	572,942	183,368	99,192	855,502

(1) Includes total proved reserves of 99 MMboe, 66 MMboe, 59 MMboe, and 64 MMboe as of December 31, 2022, 2021, 2020, and 2019, respectively, attributable to noncontrolling interests in Egypt.

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 1 MMboe of proved reserves and 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.

As previously discussed, in December 2021, the Egyptian government signed into law an agreement to modernize and consolidate a majority of the Company's Egypt PSCs. The impact of the consolidated PSC to proved reserves based on the modernized terms is 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. Approximately 96 percent of the Company's Egypt reserves are now consolidated within the modernized PSC. These estimates include Sinopec's noncontrolling interest in Egypt.

During 2020, the Company added approximately 78 MMboe from extensions, discoveries, and other additions. The Company recorded 39 MMboe of exploration and development adds in the U.S., primarily in the Southern Midland Basin (26 MMboe) associated with the Wolfcamp and Spraberry drilling programs and the remainder in the Delaware Basin and Austin Chalk. The international operations contributed 39 MMboe of exploration and development adds during 2020, with Egypt contributing 32 MMboe from onshore exploration and appraisal activity primarily in the Khalda Area and Umbarka Area concessions. The North Sea contributed 7 MMboe from drilling success, primarily in the Beryl Field. The Company had combined downward revisions of previously estimated reserves of 45 MMboe. Downward revisions related to changes in product prices accounted for 70 MMboe, engineering and performance upward revisions accounted for 27 MMboe, and downward interest revisions accounted for 2 MMboe. The Company also sold 10 MMboe of proved reserves associated with U.S. divestitures, primarily related to Eastern Shelf and Magnet Withers/Pickett Ridge.

Approximately 11 percent of the Company's year-end 2022 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, 2022, 2021, and 2020 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, 2022, 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)			
2022				
Cash inflows	$ 29,490	$ 12,819	$ 10,147	$ 52,456
Production costs	(10,221)	(2,086)	(3,241)	(15,548)
Development costs	(1,598)	(1,471)	(2,297)	(5,366)
Income tax expense	(1,389)	(2,729)	(2,631)	(6,749)
Net cash flows	16,282	6,533	1,978	24,793
10 percent discount rate	(6,422)	(1,400)	(204)	(8,026)
Discounted future net cash flows(2)	$ 9,860	$ 5,133	$ 1,774	$ 16,767
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
2020				
Cash inflows	$ 12,537	$ 5,560	$ 4,122	$ 22,219
Production costs	(6,244)	(1,704)	(2,388)	(10,336)
Development costs	(1,555)	(633)	(2,448)	(4,636)
Income tax expense	—	(1,096)	316	(780)
Net cash flows	4,738	2,127	(398)	6,467
10 percent discount rate	(1,829)	(437)	1,111	(1,155)
Discounted future net cash flows(2)	$ 2,909	$ 1,690	$ 713	$ 5,312

(1) Includes discounted future net cash flows of approximately $2.5 billion, $1.6 billion, and $563 million as of December 31, 2022, 2021, and 2020, respectively, attributable to noncontrolling interests in Egypt.

(2) Estimated future net cash flows before income tax expense, discounted at 10 percent per annum, totaled approximately $16.1 billion, $14.9 billion, and $7.1 billion as of December 31, 2022, 2021, and 2020, respectively.

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

	For the Year Ended December 31,		
	2022	2021	2020
	(In millions)		
Sales, net of production costs	$ (6,970)	$ (4,707)	$ (2,422)
Net change in prices and production costs	8,627	9,376	(5,753)
Discoveries and improved recovery, net of related costs	1,132	1,749	751
Change in future development costs	(347)	(839)	20
Previously estimated development costs incurred during the period	669	545	576
Revision of quantities	2,621	1,983	(418)
Purchases of minerals in-place	17	1	—
Accretion of discount	1,489	626	1,236
Change in income taxes	(2,371)	(1,583)	1,533
Sales of minerals in-place	(363)	(116)	(104)
Change in production rates and other	(97)	13	11
	$ 4,407	$ 7,048	$ (4,570)

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

EXHIBIT 23.1

Consent of Ryder Scott Company, L.P.

As independent petroleum engineers, we hereby consent to the incorporation by reference in this Form 10-K of Apache Corporation to our Firm's name and our Firm's review of the proved oil and gas reserve quantities of Apache Corporation as of December 31, 2022, and to the inclusion of our report, dated January 31, 2023, as an exhibit to this Form 10-K filed with the Securities and Exchange Commission.

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Houston, Texas
February 23, 2023

SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799
633 17TH STREET, SUITE 1700 DENVER, COLORADO 80202 TEL (303) 339-8110

EXHIBIT 31.1

CERTIFICATIONS

I, John J. Christmann IV, certify that:

1. I have reviewed this Annual Report on Form 10-K of Apache Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

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

EXHIBIT 31.2

CERTIFICATIONS

I, Stephen J. Riney, certify that:

1. I have reviewed this Annual Report on Form 10-K of Apache Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2023

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

EXHIBIT 32.1

APACHE CORPORATION

Certification of Principal Executive Officer
and Principal Financial Officer

I, John J. Christmann IV, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the Annual Report on Form 10-K of Apache Corporation for the period ending December 31, 2022, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of Apache Corporation.

Date: February 23, 2023

/s/ John J. Christmann IV

By:	John J. Christmann IV
Title:	Chief Executive Officer and President (principal executive officer)

I, Stephen J. Riney, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to my knowledge, the Annual Report on Form 10-K of Apache Corporation for the period ending December 31, 2022, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. §78m or §78o (d)) and that information contained in such report fairly represents, in all material respects, the financial condition and results of operations of Apache Corporation.

Date: February 23, 2023

/s/ Stephen J. Riney

By:	Stephen J. Riney
Title:	Executive Vice President and Chief Financial Officer (principal financial officer)

APACHE CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold and Royalty Interests

and

Derived Through Certain Production Sharing Contracts

SEC Parameters

As of

December 31, 2022

\s\ Ali A. Porbandarwala
Ali A. Porbandarwala, P.E.
TBPELS License No. 107652
Managing Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
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TELEPHONE (713) 651-9191

January 31, 2023

Apache Corporation
2000 Post Oak Boulevard, Suite 100
Houston, Texas 77056-4400

Ladies and Gentlemen:

At the request of Apache Corporation (Apache), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2022 prepared by Apache's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 1, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on January 12, 2023 and presented herein, was prepared for public disclosure by Apache in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent Apache's estimated net reserves attributable to the leasehold and royalty interests and derived through certain production sharing contracts in certain properties owned by Apache and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2022. The properties reviewed by Ryder Scott incorporate Apache's reserves determinations and are attributable to the interests of Apache Corporation (U.S.A), Apache Egypt Companies (Egypt), and Apache North Sea Limited (United Kingdom).

The properties reviewed by Ryder Scott account for a portion of Apache's total net proved liquid hydrocarbon and gas reserves as of December 31, 2022. Based on the estimates of total net proved reserves prepared by Apache, the reserves audit conducted by Ryder Scott addresses approximately 79.5 percent of the total proved net reserves of Apache on a barrel of oil equivalent, BOE basis as of December 31, 2022.

The properties reviewed by Ryder Scott account for a portion of Apache's total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2022. Based on the reserves and income projections prepared by Apache, the audit conducted by Ryder Scott addresses approximately 81.8 percent of the total proved discounted future net income at 10%.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserves quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Apache, it is our opinion that the overall procedures and methodologies utilized by Apache in preparing their estimates of the proved reserves as of December 31, 2022 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Apache are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Apache has informed us that in the preparation of their reserves and income projections, as of December 31, 2022, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Apache attributable to Apache's interest and entitlement in properties that we reviewed and the reserves of properties that we did not review are summarized below:

SEC PARAMETERS
Estimated Net Proved Reserves
Certain Leasehold and Royalty Interests and
Derived Through Certain Production Sharing Contracts of
Apache Corporation (Total All Countries)
As of December 31, 2022

				Reviewed by Ryder Scott			Not Reviewed			Total		
	% Crude Oil & Condensate Reserves Reviewed	% Natural Gas Liquids Reserves Reviewed	% Gas Reserves Reviewed	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF
Developed	81.9%	79.0%	78.9%	294,300	122,622	1,257,805	65,147	32,608	336,035	359,447	155,230	1,593,840
Undeveloped	71.0%	72.6%	69.9%	19,645	11,230	134,430	8,013	4,244	57,882	27,658	15,474	192,312
Total Proved	81.1%	78.4%	77.9%	313,945	133,852	1,392,235	73,160	36,852	393,917	387,105	170,704	1,786,152

SEC PARAMETERS
Estimated Net Proved Reserves
Certain Leasehold and Royalty Interests and
Derived Through Certain Production Sharing Contracts of
Apache Corporation (Summary by Country)
As of December 31, 2022

				Reviewed by Ryder Scott			Not Reviewed			Total		
	% Crude Oil & Condensate Reserves Reviewed	% Natural Gas Liquids Reserves Reviewed	% Gas Reserves Reviewed	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF	Crude Oil & Condensate MBarrels	Natural Gas Liquids MBarrels	Sales Gas MMCF
USA												
Developed	82.0	79.1	78.1	138,501	121,039	881,549	30,316	31,960	246,517	168,817	152,999	1,128,066
Undeveloped	74.2	72.6	69.9	12,031	11,172	132,077	4,189	4,226	56,898	16,220	15,398	188,975
Total Proved	81.4	78.5	77.0	150,532	132,211	1,013,626	34,505	36,186	303,415	185,037	168,397	1,317,041
Egypt												
Developed	80.2	N/A	82.2	86,618	0	328,535	21,432	0	70,946	108,050	0	399,481
Undeveloped	70.2	N/A	57.2	6,008	0	591	2,556	0	443	8,564	0	1,034
Total Proved	79.4	N/A	82.2	92,626	0	329,126	23,988	0	71,389	116,614	0	400,515
United Kingdom												
Developed	83.8	71.0	72.0	69,181	1,583	47,721	13,399	648	18,572	82,580	2,231	66,293
Undeveloped	55.9	76.3	76.5	1,606	58	1,762	1,268	18	541	2,874	76	2,303
Total Proved	82.8	71.1	72.1	70,787	1,641	49,483	14,667	666	19,113	85,454	2,307	68,596

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousand of barrels (MBarrels). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The reference above to barrel of oil equivalent (BOE), is the method wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various proved reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed reserves included herein consist of the producing, shut-in and behind pipe status categories.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Apache's request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves, prepared by Apache, for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 90 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through November 2022, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Apache or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 10 percent of the proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

All of the proved developed non-producing and the undeveloped status categories that we reviewed were estimated by the volumetric method or analogy. The volumetric analysis utilized pertinent well and seismic data, reports and other data furnished to Ryder Scott by Apache for our review or which we have obtained from public data sources that were available through November, 2022. The data utilized from the analogues in conjunction with well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves, many factors and assumptions are considered including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Apache relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon benchmark prices furnished by Apache for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract.

Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2022 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices, provided by Apache, appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used by Apache for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements. In cases where there are numerous contracts or price references within the same geographic area, the benchmark price is represented by the unweighted arithmetic average of the initial 12-month average first-day-of-the-month benchmark prices used.

The product prices that were actually used by Apache to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache.

The table below summarizes Apache's net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as Apache's "average realized prices." The average realized prices shown in the table below were determined from Apache's estimate of the total future gross revenue before production taxes for the properties reviewed by us and Apache's estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the following table is presented in accordance with SEC disclosure requirements for each of the geographic areas reviewed by us.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$93.82/Bbl	$94.18/Bbl
	NGLs	Mt. Belvieu Non-Tet Propane	$48.05/Bbl	$31.36/Bbl
	Gas	Henry Hub	$6.186/MMBTU	$5.16/Mcf
Egypt	Oil/Condensate	Brent	$101.24/Bbl	$100.19/Bbl
	NGLs	Brent	$101.24/Bbl	N/A
	Gas	Contracts	Contract	$2.855/Mcf
United Kingdom	Oil/Condensate	Brent	$101.24/Bbl	$98.66/Bbl
	NGLs	Brent	$101.24/Bbl	$69.75/Bbl
	Gas	UK National Balancing Point (NBP)	$24.285/MMBTU	$22.61/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in Apache's individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Operating costs furnished by Apache are based on the operating expense reports of Apache and include only those costs directly applicable to the leases, contract areas, or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases, contract areas, and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases, contract areas, and wells under terms of operating agreements. Other costs include transportation and/or processing fees as deductions. The operating costs furnished by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Apache are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Apache were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Apache. The estimated net cost of abandonment after salvage was included by Apache for properties where abandonment costs net of salvage were material. Apache's estimates of the net abandonment costs were accepted without independent verification.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Apache's plans to develop these reserves as of December 31, 2022. The implementation of Apache's development plans as presented to us is subject to the approval process adopted by Apache's management. As the result of our inquiries during the course of our review, Apache has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Apache's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Apache. Apache has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Apache has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Apache were held constant throughout the life of the properties.

Apache's forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Apache to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Apache. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Apache's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

The proved reserves reported herein are limited to the period prior to expiration of current contracts providing the legal right to produce or a revenue interest in such production unless evidence indicates that contract renewal is reasonably certain.

The proved reserves for the properties located in Egypt are subject to the contractual fiscal terms contained in production sharing contracts. For these properties, Ryder Scott audited the gross economic inputs used by Apache in the economic models for Egypt through a comparison of Apache's and Ryder Scott's gross economic volumes. Apache's gross economic volumes were then used as input to the economic models to generate the net interests used to determine the net reserves summarized in this report. Ryder Scott reviewed the fiscal terms of such contracts and discussed with Apache the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Apache's representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Apache operates or has interests. Apache's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, contract terms, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms of various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the quantities as estimated by Apache.

The estimates of proved reserves presented herein were based upon a review of the properties in which Apache owns and derives an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by Apache for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of Apache are responsible for the preparation of reserves estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

Apache has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Apache's forecast of future proved production, we have relied upon data furnished by Apache with respect to property interests owned or derived, production and well tests from examined wells, normal direct costs of operating the wells, leases or contract areas, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Apache. We consider the factual data furnished to us by Apache to be appropriate and sufficient for the purpose of our review of Apache's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Apache and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Apache, it is our opinion that the overall procedures and methodologies utilized by Apache in preparing their estimates of the proved reserves as of December 31, 2022 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Apache are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Apache in their estimate of proved reserves to be effective and in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

We were in reasonable agreement with Apache's estimates of proved reserves for the properties which we reviewed; although in certain cases there was more than an acceptable variance between Apache's estimates and our estimates due to a difference in interpretation of data or due to our having access to data which were not available to Apache when its reserves estimates were prepared. However notwithstanding, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned or derived by Apache.

Other Properties

Other properties, as used herein, are those properties of Apache which we did not review. The proved net reserves attributable to the other properties account for approximately 20.5 percent of the total proved net liquid hydrocarbon and gas reserves of Apache on a barrel of oil equivalent, BOE basis, based on estimates prepared by Apache as of December 31, 2022. The other properties represent approximately 18.2 percent of the total proved discounted future net income at 10% based on the unescalated pricing policy of the SEC as taken from reserves and income projections prepared by Apache.

The same technical personnel of Apache were responsible for the preparation of the reserves estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Apache. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Apache Corporation.

Apache makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Apache has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3, Form S-4, and Form S-8 of Apache, of the references to our name, as well as to the references to our third party report for Apache, which appears in the December 31, 2022 annual report on Form 10-K of Apache. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Apache.

We have provided Apache with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Apache and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

\s\ Ali A. Porbandarwala

Ali A. Porbandarwala, P.E.
TBPELS License No. 107652
Managing Senior Vice President

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Ali A. Porbandarwala was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Porbandarwala, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2008, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Porbandarwala served in a number of engineering positions with ExxonMobil Corporation. For more information regarding Mr. Porbandarwala's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Employees.

Mr. Porbandarwala earned a Bachelor of Science degree in Chemical Engineering from The University of Kansas in 2001 and a Masters in Business Administration from The University of Texas at Austin in 2007 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and a member of the Society of Petroleum Evaluation Engineers. Mr. Porbandarwala also served as the Chairman of the annual Ryder Scott Reserves Conference for four years.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Porbandarwala fulfills. As part of his 2022 continuing education hours, Mr. Porbandarwala attended 18 hours of formalized training including the 2022 Virtual Ryder Scott Reserves Conference and various other professional society presentations specifically relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register.

Based on his educational background, professional training and more than 14 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Porbandarwala has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> *(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and*
>
> *(B) The project has been approved for development by all necessary parties and entities, including governmental entities.*

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.