2025
Annual Report

ConocoPhillips

ConocoPhillips at a Glance

As of Dec. 31, 2025

2025 HIGHLIGHTS

Financial

- Distributed $9.0 billion, or **45% of cash from operations**, to shareholders.
- **Increased ordinary dividend by 8%**, in line with goal to deliver top-quartile dividend growth in S&P 500.
- **Improved net debt by ~$2 billion** compared with year-end 2024.
- **Outperformed** initial production, capital and cost guidance.

Strategic

- Integrated Marathon Oil with **>25% more resource** and **>$1 billion** synergy capture.
- Made strong progress on **>$1 billion cost reduction and margin enhancement** efforts.
- Placed initial 5 MTPA of Port Arthur LNG Phase 1 offtake; **total offtake now 10 MTPA**.
- **Achieved** annual Scope 1 and 2 GHG emissions intensity target.

Operational

- Produced **2,375** thousand barrels of oil equivalent per day.
- **Advanced** Willow project in Alaska and equity LNG projects in Qatar and on the U.S. Gulf Coast.
- Delivered Lower 48 **drilling and completion efficiencies >15%** year over year.
- Achieved **first oil at Surmont Pad 104W-A** on budget and ahead of schedule.

WHO WE ARE

As a leading global exploration and production company, ConocoPhillips is uniquely equipped to deliver reliable, responsibly produced oil and gas. Our deep, durable and diverse portfolio is built to meet growing global energy demands. Together with our high-performing operations and continuously advancing technology, we are well positioned to deliver strong, consistent financial results, now and for decades to come.

$122B
in total assets

14
Countries with operations and activities

One of the world's leading exploration and production companies

Balanced, diversified global portfolio

2025

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

ConocoPhillips

Form 10-K

(Mark One)

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

For the fiscal year ended **December 31, 2025**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _______________ to _______________

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer identification No.)*

925 N. Eldridge Parkway, Houston, TX 77079

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **281-293-1000**

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

Title of each class	Trading symbols	Name of each exchange on which registered
Common Stock, $.01 Par Value	COP	New York Stock Exchange
7% Debentures due 2029	CUSIP—718507BK1	New York Stock Exchange

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

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

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

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

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

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

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

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

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

If securities are registered pursuant to Section 12(b) of the Act, indicate by checkmark 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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $89.74, was $112.0 billion.

The registrant had 1,222,339,152 shares of common stock outstanding at January 31, 2026.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2026 (Part III)

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Commonly Used Abbreviations

The following industry-specific, accounting and other terms and abbreviations may be commonly used in this report.

Currencies

$ or USD	U.S. dollar
CAD	Canadian dollar
EUR	Euro
GBP	British pound
NOK	Norwegian kroner

Units of Measurement

BBL	barrel
BCF	billion cubic feet
BOE	barrels of oil equivalent
MBD	thousands of barrels per day
MCF	thousand cubic feet
MM	million
MMBOE	million barrels of oil equivalent
MBOED	thousand barrels of oil equivalent per day
MMBOED	million barrels of oil equivalent per day
MMBTU	million British thermal units
MMCFD	million cubic feet per day
MTPA	million tonnes per annum

Industry

BLM	Bureau of Land Management
CBM	coalbed methane
E&P	exploration and production
FEED	front-end engineering and design
FID	final investment decision
FPS	floating production system
FPSO	floating production, storage and offloading
G&G	geological and geophysical
JOA	joint operating agreement
LNG	liquefied natural gas
NGLs	natural gas liquids
OPEC	Organization of Petroleum Exporting Countries
PSC	production sharing contract
PUDs	proved undeveloped reserves
SAGD	steam-assisted gravity drainage
WCS	Western Canadian Select
WTI	West Texas Intermediate

Accounting

ARO	asset retirement obligation
ASC	accounting standards codification
ASU	accounting standards update
DD&A	depreciation, depletion and amortization
EPS	earnings per share
FASB	Financial Accounting Standards Board
FIFO	first-in, first-out
G&A	general and administrative
GAAP	generally accepted accounting principles
LIFO	last-in, first-out
NPNS	normal purchase normal sale
PP&E	properties, plants and equipment
VIE	variable interest entity

Miscellaneous

CERCLA	Federal Comprehensive Environmental Response Compensation and Liability Act
EPA	Environmental Protection Agency
ESG	environmental, social and governance
EU	European Union
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
HSE	health, safety and environment
ICC	International Chamber of Commerce
ICSID	World Bank’s International Centre for Settlement of Investment Disputes
IRS	Internal Revenue Service
OTC	over-the-counter
NYSE	New York Stock Exchange
SEC	U.S. Securities and Exchange Commission
TSR	total shareholder return
U.K.	United Kingdom
U.S.	United States of America
VROC	variable return of cash

Part I

Unless otherwise indicated, "the company," "we," "our," "us" and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2—Business and Properties, contain forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words *"ambition," "anticipate," "believe," "budget," "continue," "could," "effort," "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "objective," "outlook," "plan," "potential," "predict," "projection," "seek," "should," "target," "will," "would"* and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the headings "Risk Factors" beginning on page *18* and "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page *62*.

Items 1 and 2. Business and Properties

Corporate Structure

ConocoPhillips is an independent E&P company headquartered in Houston, Texas with operations and activities in 14 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe, Africa and Asia; LNG developments; oil sands in Canada; and an inventory of global exploration prospects. On December 31, 2025, we employed approximately 9,900 people worldwide and had total assets of about $122 billion. Total company production for the year was 2,375 MBOED.

ConocoPhillips was incorporated in the state of Delaware in 2001 in connection with and in anticipation of the merger between Conoco Inc. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002. In April 2012, ConocoPhillips completed the separation of the downstream business into an independent, publicly traded energy company, Phillips 66.

Segment and Geographic Information

We manage our operations through five operating segments, defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; and Asia Pacific. For operating segment and geographic information, *see Note 22*.

We explore for, produce, transport and market crude oil, bitumen, natural gas, NGLs and LNG on a worldwide basis. At December 31, 2025, our operations were producing in the U.S., Norway, Canada, Australia, Malaysia, Libya, China, Qatar and Equatorial Guinea.

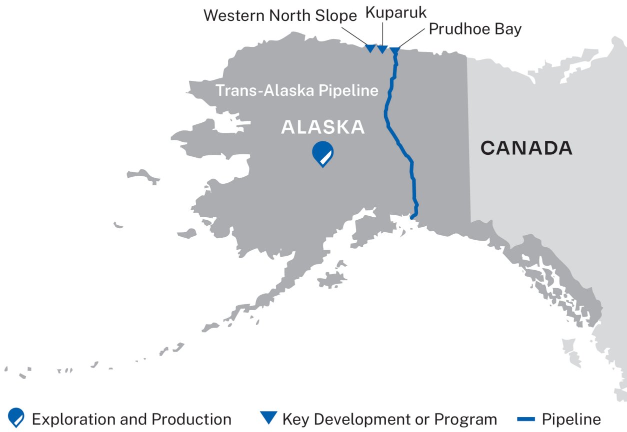
The information listed below appears in the *"Supplementary Data - Oil and Gas Operations"* disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil, NGLs, natural gas and bitumen reserves.
- Net production of crude oil, NGLs, natural gas and bitumen.
- Average sales prices of crude oil, NGLs, natural gas and bitumen.
- Average production costs per BOE.
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the *"Supplementary Data - Oil and Gas Operations"* disclosures following the Notes to Consolidated Financial Statements. Approximately 84 percent of our proved reserves are in countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six MCF of natural gas converts to one BOE. *See Management's Discussion and Analysis of Financial Condition and Results of Operations* for a discussion of factors that will enhance the understanding of the following summary reserves table.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2025**	2024	2023
Crude oil			
Consolidated operations	**3,321**	3,406	3,032
Equity affiliates	**103**	108	89
Total crude oil	**3,424**	3,514	3,121
Natural gas liquids			
Consolidated operations	**1,166**	1,147	892
Equity affiliates	**59**	62	48
Total natural gas liquids	**1,225**	1,209	940
Natural gas			
Consolidated operations	**1,617**	1,629	1,408
Equity affiliates	**969**	977	879
Total natural gas	**2,586**	2,606	2,287
Bitumen			
Consolidated operations	**402**	483	410
Total bitumen	**402**	483	410
Total consolidated operations	**6,506**	6,665	5,742
Total equity affiliates	**1,131**	1,147	1,016
Total company	**7,637**	7,812	6,758

Alaska



The Alaska segment primarily explores for, produces, transports and markets crude oil, natural gas and NGLs. We are the largest crude oil producer in Alaska and have major ownership interests in the Prudhoe Bay, Kuparuk and Western North Slope asset areas. Additionally, we are one of Alaska's largest owners of state, federal and fee exploration leases, with approximately one million net undeveloped acres at year-end 2025. Alaska operations contributed 12 percent of our consolidated liquids production and one percent of our consolidated natural gas production.

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Greater Prudhoe Area	36.5 %	Hilcorp	63	15	40	85
Greater Kuparuk Area	94.2-99.8	ConocoPhillips	75	—	—	75
Western North Slope	100.0	ConocoPhillips	39	—	1	39
Total Alaska			177	15	41	199

Willow Project

The Bear Tooth Unit in the Western North Slope includes the Willow Project (Willow). In December 2023, we announced Willow FID. The project will consist of three drill sites, an operations center and camp, and a processing facility. In 2025, the project completed the peak construction season, which included gravel and pipeline construction and operations center hookup and installation, and is expected to achieve near 50 percent project completion this winter season. Additionally, fabrication of the processing facility is on schedule for transport to the North Slope in 2027. First oil is anticipated in early 2029.

Greater Prudhoe Area

The Greater Prudhoe Area includes the Prudhoe Bay Unit, which consists of the Prudhoe Bay Field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest conventional oil field in North America, is the site of a large waterflood and enhanced oil recovery operation, supported by a large gas and water processing operation. Field installations include seven production facilities, two gas plants, two seawater plants and a central power station. In 2025, on average, there were three rigs drilling throughout the year.

Greater Kuparuk Area

The Greater Kuparuk Area includes the Kuparuk River Unit, which consists of the Kuparuk Field and six satellite fields. Field installations include three central production facilities which separate oil, natural gas and water, and a seawater treatment plant. In 2025, on average, we operated two drilling rigs and one workover rig. The Nuna project, which targets the Moraine reservoir, was sanctioned in 2023 and achieved first oil in the fourth quarter of 2024. We drilled additional wells in 2025 and plan to continue drilling activity through 2027. The Coyote reservoir, discovered in 2021, progressed to development in 2023, with additional wells drilled in 2024 and 2025, and a pad expansion project planned for 2026.

Western North Slope

The Western North Slope includes the Bear Tooth Unit (as highlighted above), the Colville River Unit and the Greater Mooses Tooth Unit. These units also leverage shared regional infrastructure, which underpins base operations and facilitates continued development across the Western North Slope. In 2025, we operated one part-time drilling rig in the Colville River Unit.

The Colville River Unit includes the Alpine Field and four satellite fields. Field installations include one central production facility, which separates oil, natural gas and water.

The Greater Mooses Tooth Unit is the first unit established entirely within the National Petroleum Reserve Alaska (NPR-A). The unit was constructed in two phases: Greater Mooses Tooth #1 (GMT1) and Greater Mooses Tooth #2 (GMT2).

Exploration

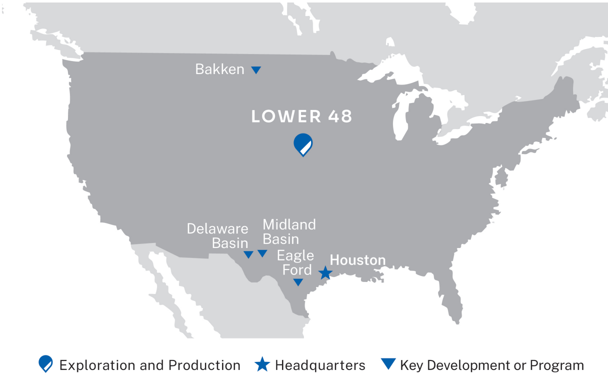
We are continuing our exploration activities in the NPR-A with a planned four-well drilling program this 2026 winter season.

Transportation

We transport the petroleum liquids produced on the North Slope to Valdez, Alaska through an 800-mile pipeline that is part of the Trans-Alaska Pipeline System (TAPS). We have a 29.5 percent ownership interest in TAPS, and also have ownership interests in, and operate the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

We manage the marine transportation of our North Slope production using five company-owned, double-hulled tankers, and charter third-party vessels, as necessary. The tankers deliver oil from Valdez, Alaska, primarily to refineries on the west coast of the U.S.

Lower 48



The Lower 48 segment consists of operations located in the 48 contiguous U.S. states, with a portfolio mainly consisting of low cost of supply, short cycle time, resource-rich unconventional plays and commercial operations. The majority of our acreage is unconventional. Based on 2025 production volumes, the Lower 48 is our largest segment and contributed 67 percent of our consolidated liquids production and 74 percent of our consolidated natural gas production.

	2025			
	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production				
Delaware Basin	321	171	1,011	661
Eagle Ford	202	102	516	390
Bakken	114	50	241	204
Midland Basin	103	48	251	192
Other	9	11	100	37
Total Lower 48	749	382	2,119	1,484

Delaware Basin

We hold approximately 782,000 net acres in the Delaware Basin, spanning west Texas through southeast New Mexico. Current development activity targets prospects in the Avalon, Bone Springs, Wolfcamp and Woodford formations while balancing leasehold obligations and permit terms. We operated ten rigs and three frac crews on average during 2025, resulting in 176 operated wells drilled and 161 operated wells brought online.

Eagle Ford

We hold approximately 489,000 net acres in the Eagle Ford, located in south Texas. The current focus is on full-field development, using customized well spacing and stacking patterns adapted through reservoir analysis. We operated seven rigs and three frac crews on average during 2025, resulting in 251 operated wells drilled and 264 operated wells brought online.

Bakken

We hold approximately 799,000 net acres in the Williston Basin, located in North Dakota and eastern Montana. The primary producing zones are the Middle Bakken and Three Forks formations. We operated three rigs and one frac crew on average during 2025, resulting in 72 operated wells drilled and 98 operated wells brought online.

Midland Basin

We hold approximately 416,000 net acres in the Midland Basin, located in west Texas. The current development strategy is focused on full-field development utilizing multi-well pad projects targeting Barnett, Spraberry and Wolfcamp reservoir targets. We operated three rigs and one frac crew on average during 2025, resulting in 86 operated wells drilled and 94 operated wells brought online.

Partner-Operated

We participate in partner-operated wells when they align with our investment decision criteria and development strategies. In 2025, we participated in partner-operated wells with varying working interests across our Lower 48 portfolio.

Facilities

We operate and own, with varying interests, centralized processing facilities in Texas and New Mexico in support of our Delaware, Eagle Ford and Midland assets.

Canada

Our Canadian operations consist of the Surmont oil sands development in Alberta, the liquids-rich Montney unconventional play in British Columbia and commercial operations. In 2025, operations in Canada contributed nine percent of our consolidated liquids production and five percent of our consolidated natural gas production.

			2025				
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production							
Surmont	100.0 %	ConocoPhillips	—	—	—	133	133
Montney	100.0	ConocoPhillips	17	6	125	—	44
Total Canada			17	6	125	133	177

Surmont
The Surmont oil sands leases are located south of Fort McMurray, Alberta. Surmont is a 100 percent working interest asset that offers sustained, long-life production. We are focused on keeping facilities full, structurally lowering costs, reducing GHG intensity and optimizing asset performance. In the third quarter of 2025, we commenced drilling of Pad 104W-B and in the fourth quarter of 2025, we achieved first production from Pad 104W-A.

Our bitumen resources in Canada are produced via SAGD, an enhanced thermal oil recovery method where steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing. Operations include two central processing facilities for treatment and blending of bitumen, and a diluent recovery unit. These facilities have allowed the asset to lower blend ratio and diluent supply costs, while gaining protection from diluent supply disruptions and increased market access for our product. At December 31, 2025, we held approximately 684,000 net acres of land in the Athabasca Region of northeastern Alberta.

Montney
The Montney is a liquids-rich unconventional play located in northeastern British Columbia. At December 31, 2025, we held approximately 297,000 unconventional net acres of land in the Montney. In 2025, we operated two rigs and one frac crew resulting in 31 wells drilled and 23 operated wells brought online.

Europe, Middle East and North Africa

The Europe, Middle East and North Africa segment consists of operations principally located in the Norwegian sector of the North Sea, the Norwegian Sea, Qatar, Libya, Equatorial Guinea and commercial and terminalling operations in the U.K. In 2025, operations in Europe, Middle East and North Africa contributed eight percent of our consolidated liquids production and 18 percent of our consolidated natural gas production.

Norway

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Greater Ekofisk Area	28.3 - 35.1%	ConocoPhillips	38	2	83	54
Heidrun	24.0	Equinor	9	—	35	15
Troll	1.6	Equinor	1	—	66	12
Aasta Hansteen	10.0	Equinor	—	—	66	11
Alvheim	20.0	Equinor	7	—	16	9
Visund	9.1	Aker BP	1	1	44	9
Other	Various	Equinor	7	—	20	11
Total Norway			63	3	330	121

Greater Ekofisk Area
The Greater Ekofisk Area is located offshore Stavanger, Norway, in the North Sea, and is comprised of five producing fields. Crude oil is exported to our operated terminal located at Teesside, U.K., and the natural gas is exported to Emden, Germany.

Partner-Operated
We participate in various partner-operated fields located either in the Norwegian Sea or northern part of the North Sea. Crude oil and natural gas are produced and transported to various processing plants and terminals, primarily in Norway and the U.K.

Exploration
In 2025, we drilled the second appraisal well in the 2020 Slagugle discovery on PL891. The well encountered hydrocarbons and a significant data acquisition program was completed. The collected data will be analyzed to evaluate a possible future development. We also participated in the Bounty Updip exploration well on PL886 in the Norwegian Sea. The well was expensed as a dry hole. Additionally, we participated in the Othello South exploration well in the Heidrun area of the Norwegian Sea, which encountered hydrocarbons. In 2025, we were awarded two new exploration licenses in the North Sea, PL1248 and PL1259, and one acreage addition, PL044D.

Transportation
We have a 35.1 percent ownership interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a crude oil stabilization and NGLs processing facility in Teesside, U.K.

Facilities
We operate and have a 40.25 percent ownership interest in a crude oil stabilization and NGLs processing facility at Teesside, U.K. to support our Norway operations.

Qatar

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
QatarEnergy LNG N(3)	30.0 %	QatarEnergy LNG	12	8	373	82

QatarEnergy LNG N(3) (N3), is an integrated development jointly owned by QatarEnergy (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). N3 consists of upstream natural gas production facilities, which produce approximately 1.4 gross BCF per day of natural gas from Qatar’s North Field over a 25-year life, in addition to a 7.8 million gross tonnes per year LNG facility. LNG is shipped in leased LNG carriers destined for sale globally, while liquids are sold into the domestic market or marketed internationally through QatarEnergy Marketing.

N3 executed the development of the onshore and offshore assets as a single integrated development with QatarEnergy LNG N(4) (N4), a joint venture between QatarEnergy and Shell plc. This included the joint development of offshore facilities situated in a common offshore block in Qatar's North Field, as well as the construction of two identical LNG process trains and associated gas treating facilities for both the N3 and N4 joint ventures. Production from the LNG trains and associated facilities is mutualized between the two joint ventures.

We have a 25 percent interest in both QatarEnergy LNG NFE (4) (NFE4) and QatarEnergy LNG NFS (3) (NFS3) joint ventures, which are participating in the North Field East (NFE) and North Field South (NFS) LNG projects, respectively. *See Note 3* and *Note 4.*

Libya

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Waha Concession	20.4 %	Waha Oil Co.	60	—	32	65

The Waha Concession is made up of multiple concessions and encompasses approximately 13 million acres onshore in the Sirte Basin for exploration and production activity. Oil is transported by pipeline to the Es Sider terminal for export. Natural gas is transported and sold domestically. Current production comes from 13 existing fields within the Waha Concession.

In January 2026, we signed an agreement with the Libyan Ministry of Oil and Gas and the National Oil Corporation of Libya to extend the Waha Concession up to December 31, 2050, with new fiscal terms, subject to normal regulatory approvals.

Equatorial Guinea

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Alba Unit	64.2 %	ConocoPhillips	8	5	149	38

We have varying stages of oil and gas exploration, development and production activities in Equatorial Guinea. We operate in both the Alba and Block D PSCs that form the Alba Unit located offshore Equatorial Guinea.

Gas Processing

The following facilities located on Bioko Island allow us to further monetize natural gas production from the Alba Unit and are accounted for as equity method investments and are reflected in the "Equity in earnings of affiliates" line of our consolidated income statement.

We own a 52.2 percent interest in the Alba Plant LLC, our joint venture with Chevron Corporation (27.8 percent) and Sociedad Nacional de Gas de Guinea Ecuatorial (SONAGAS) (20 percent), which operates an onshore liquified petroleum gas (LPG) processing plant. Alba Plant LLC processes Alba Unit natural gas under a fixed-rate long-term contract. The LPG processing plant extracts condensate and LPG from the natural gas stream and sells it at market prices, with our share of the revenue reflected in the "Equity in earnings of affiliates" line of our consolidated income statement. Processed natural gas is delivered to Equatorial Guinea LNG Holdings Limited (EG LNG) for liquefaction and storage. We market our share of LNG to third parties indexed at global LNG prices.

We own a 56 percent interest in EG LNG, our joint venture with SONAGAS (37.9 percent) and Marubeni Gas Development UK Limited (6.1 percent), which operates a 3.7 MTPA LNG production facility. In January 2024, we began a five-year LNG sales agreement for a portion of our equity gas from the Alba Unit, providing us with additional exposure to the European LNG market.

We own a 45 percent interest in Atlantic Methanol Production Company LLC (AMPCO), our joint venture with Chevron Corporation (45 percent) and SONAGAS (10 percent), which operates a methanol plant. The plant is currently offline.

Additionally, Alba Plant LLC and EG LNG process third-party gas from the Alen Field under a combination of tolling fee and profit-sharing arrangements which are reflected in the "Equity in earnings of affiliates" line of our consolidated income statement.

Asia Pacific

The Asia Pacific segment has exploration and production operations in China, Malaysia, Australia and commercial operations in China, Singapore and Japan. In 2025, operations in the Asia Pacific segment contributed four percent of our consolidated liquids production and two percent of our consolidated natural gas production.

Australia

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Australia Pacific LNG	47.5 %	ConocoPhillips/ Origin Energy	—	—	833	139

Australia Pacific LNG Pty Ltd. (APLNG), our joint venture with Origin Energy Limited (Origin) and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia, to supply the domestic gas market and convert the CBM into LNG for export. Origin operates APLNG's upstream production and pipeline system, and we operate the downstream LNG facility, located on Curtis Island near Gladstone, Queensland, as well as the LNG export sales business.

We operate two fully subscribed 4.5 MTPA LNG trains. Approximately 3,500 net wells are ultimately expected to supply both the LNG sales contracts and domestic gas market. The wells are supported by gathering systems, central gas processing and compression stations, water treatment facilities and an export pipeline connecting the gas fields to the LNG facilities. The LNG is being sold to Sinopec under a 20-year sales agreement for 7.6 MTPA of LNG, and Japan-based Kansai Electric Power Co., Inc. under a 20-year sales agreement for approximately one MTPA of LNG.

For additional information, *see Note 4* and *Note 8*.

Exploration
We own a 51 percent working interest in both Exploration Permit (T/49P) and (VIC/P79) located in the Otway Basin, Australia, after transferring 29 percent working interest to Korea National Oil Corporation in 2025. From November 2025 to early 2026, we drilled two exploration wells in VIC/P79. The first well, Essington-1, encountered hydrocarbons and continues to be evaluated. The second well, Charlemont-1, found no commercial hydrocarbons and was expensed as a dry hole in the fourth quarter of 2025.

China

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Penglai	49.0 %	CNOOC	34	—	—	34

Penglai
The Penglai 19-3, 19-9 and 25-6 fields are located in the Bohai Bay Block 11/05 and are being developed in stages from large offshore platforms and a FPSO. Most of the crude oil produced from the block is sold to the domestic market in China, with the remainder exported to international markets.

Phase 4B consists of two wellhead platforms. First production was achieved in the fourth quarter of 2023. This project could include up to 144 new wells, 95 of which have been completed and brought online as of December 2025.

Phase 5 consists of two new wellhead platforms and four wellhead platform expansions. First production was achieved in the fourth quarter of 2024. This project could include up to 91 new wells, 25 of which have been completed and brought online as of December 2025.

Malaysia

			2025			
	Interest	Operator	Crude Oil MBD	NGL MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production						
Gumusut	29.5 %	Shell	14	—	—	14
Malikai	35.0	Shell	1	—	63	12
Kebabangan (KBB)	30.0	ConocoPhillips	9	—	—	9
Siakap North-Petai	21.0	PTTEP	1	—	—	1
Total Malaysia			25	—	63	36

We have varying stages of exploration, development and production activities in Malaysia, with working interests in four PSCs, and as of January 2025, sole operatorship at the Kebabangan Cluster (KBBC), our first operated producing asset in Malaysia. These PSCs are located in waters off the eastern Malaysian state of Sabah: Block G, Block J, KBBC and the Ubah Cluster.

Block J
Gumusut
We own a 29.5 percent working interest in the unitized Gumusut Field. Development associated with Gumusut Phase 4, a four-well program targeting the Brunei acreage of the unitized Gumusut Field that straddles Malaysia and Brunei waters, completed drilling in 2024 with first production achieved in early 2025. The unitized Gumusut Field is operated on a FPS with oil evacuation via a pipeline to the Sabah Oil and Gas Terminal (SOGT) for tanker liftings.

KBBC
We own a 30 percent working interest in the KBB, Kamunsu East and Kamunsu East Upthrown Canyon gas and condensate fields.

KBB
Gas is transported from the KBB platform via pipeline for sale to the domestic gas market. Since 2019, KBB tied-in to a nearby third-party floating LNG vessel, which provided additional gas offtake capacity.

Block G

Malikai

We own a 35 percent working interest in Malikai. Malikai Phase 2 development first oil was achieved in February 2021. Malikai operates on a tension leg platform and pipes oil to the KBB platform for processing. Oil evacuation is via pipeline to SOGT for tanker liftings.

Siakap North-Petai

We own a 21 percent working interest in the unitized Siakap North-Petai (SNP) oil field. First oil from SNP Phase 2 was achieved in November 2021. The subsea system in the SNP oil field is tied back to a FPSO operated by PTTEP.

Exploration

We operate one exploration PSC with a 35 percent working interest in the Ubah Cluster. Located off the coast of Sabah, offshore Malaysia and near the KBBC, the Ubah Cluster encompasses 11 thousand net acres. We continue to evaluate the block and are using information from seismic to optimize future plans.

At the beginning of 2025, we operated two additional exploration PSCs off the coast of Sarawak, offshore Malaysia, Block SK304 encompassing 1.8 million net acres and Block WL4-00 encompassing 0.3 million net acres. We relinquished both blocks, effective in the first and fourth quarter of 2025, respectively.

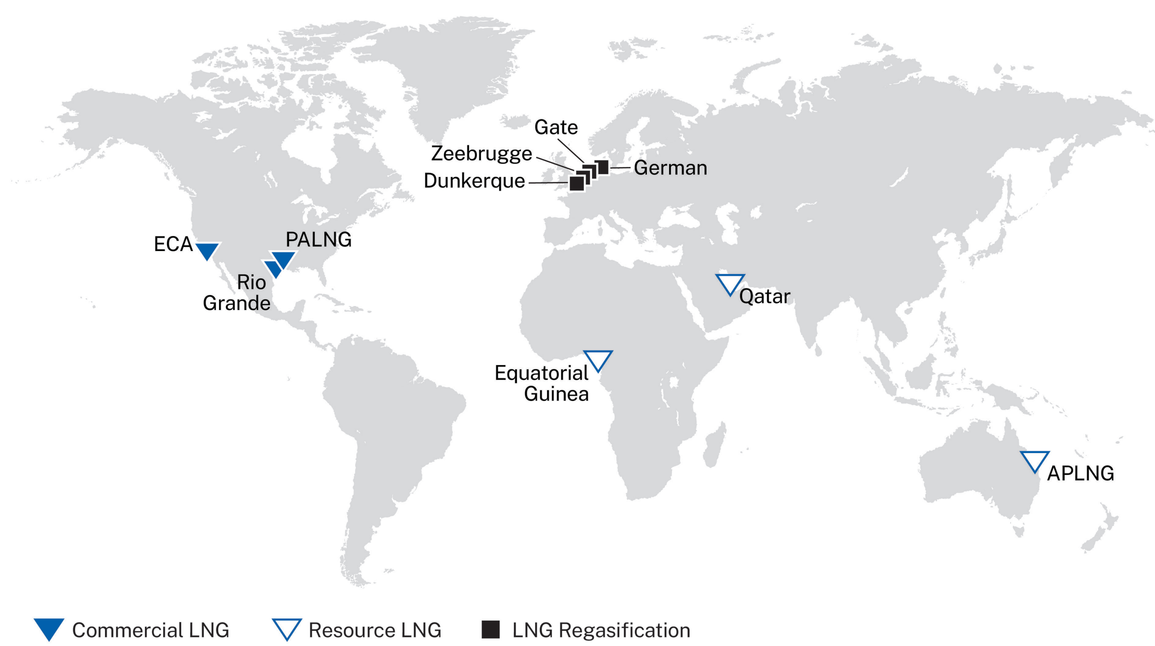
Other

Marketing Activities
Our Commercial organization manages our worldwide commodity portfolio, which includes natural gas, crude oil, bitumen, NGLs, LNG and power. Marketing activities are performed through offices in the U.S., Canada, Europe and Asia. In marketing our production, we attempt to minimize flow disruptions, maximize realized prices and manage credit-risk exposure. Commodity sales are generally made at prevailing market prices at the time of sale. We also purchase and sell third-party commodity volumes to better position the company to satisfy customer demand while fully utilizing transportation and storage capacity.

Crude Oil, Bitumen and NGLs
Our crude oil, bitumen and NGL revenues are derived from production in the U.S., Canada, Asia, Africa and Europe. These commodities are primarily sold under contracts with prices based on market indices, adjusted for location, quality and transportation.

Natural Gas
Our natural gas production, along with third-party purchased gas, is primarily marketed in the U.S., Canada and Europe. Our natural gas is sold to a diverse client portfolio, which includes local distribution companies; gas and power utilities; large industrials; independent, integrated or state-owned oil and gas companies; as well as marketing companies. To reduce our market exposure and credit risk, we also transport natural gas via firm and interruptible transportation agreements to major market hubs.

LNG



We have investments in LNG facilities which are supplied with equity gas production in Australia, Qatar and Equatorial Guinea. We also have a 30 percent direct equity holding in Port Arthur Liquefaction Holdings, LLC (PALNG) for Phase 1 of the Port Arthur LNG project, which is scheduled to start up in 2027. Additionally, as part of our LNG strategy to build a dynamic portfolio and expand our footprint across the value chain, we have various commercial LNG offtake agreements in North America totaling 10.2 MTPA with offtake commencing between 2026-2031. Furthermore, we currently have a total regasification capacity in Europe of approximately 6.7 MTPA. We continue to progress discussions across all major LNG producing and consuming regions and markets to further add high-quality positions to our portfolio. *See Note 3.*

Emergency Response Partnerships
Emergency response partnerships are vital for effective disaster management. By uniting government agencies, non-profits, private companies and community groups, these partnerships enhance preparedness, response and recovery efforts. We maintain memberships in several global response and containment partnerships as a key element of our emergency response preparedness program, complementing our internal response resources.

Oil Spill Response Organizations (OSROs)
We maintain memberships in several OSROs, many of which are not-for-profit cooperatives owned by member companies. We may actively participate in these organizations as members of the board of directors, steering committees, work groups or other supporting roles. In North America, our primary OSROs include the Marine Spill Response Corporation for the continental U.S. and Alaska Clean Seas and Ship Escort/Response Vessel System for the Alaska North Slope and Prince William Sound, respectively. Internationally, we maintain memberships in various OSROs, including Oil Spill Response Limited, the Norwegian Clean Seas Association for Operating Companies, the Australian Marine Oil Spill Center and Petroleum Industry of Malaysia Mutual Aid Group.

Technology
We have several technology programs that improve our ability to develop unconventional reservoirs, increase recovery from our legacy fields, improve the efficiency of our exploration program, produce heavy oil economically with lower emissions and implement sustainability measures.

We are the second-largest LNG liquefaction technology provider globally based on total global installed production capacity. Our Optimized Cascade® LNG liquefaction technology has been licensed for use in 28 LNG trains around the world, with FEED studies ongoing for additional trains.

We continue to evaluate opportunities to support our operational emissions reduction objectives and evaluate lower carbon opportunities for future competitive investment with the same discipline we follow in our traditional business investment and capital allocation process.

Delivery Commitments
We sell crude oil and natural gas from our producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 9 MTPA of LNG, 820 billion cubic feet of natural gas and 175 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2042. We have a variety of options to fulfill our delivery commitments including third-party purchases, as supported by our gas management and power supply agreements, LNG sales agreements, proved developed reserves and PUDs. See the disclosure on “Proved Undeveloped Reserves” in the *“Supplementary Data - Oil and Gas Operations”* section following the Notes to Consolidated Financial Statements, for information on the development of PUDs.

Competition
ConocoPhillips is one of the world’s leading E&P companies based on both production and reserves, with a globally diversified asset portfolio. We compete with private, public and state-owned companies in all facets of the E&P business. Some of our competitors are larger and have greater resources. Each of our segments is highly competitive, with no single competitor, or small group of competitors, dominating.

We compete with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, LNG, NGLs and natural gas in an efficient, cost-effective manner. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; equipment and personnel; economic analysis in connection with portfolio management and safely operating oil and gas producing properties.

Human Capital Management

At ConocoPhillips, our strategy, performance, culture and reputation are fueled by our workforce. Attracting, retaining and developing a world-class workforce is a competitive imperative within our complex industry. Our human capital management (HCM) approach is based on our core SPIRIT Values – Safety, People, Integrity, Responsibility, Innovation and Teamwork – which set the tone for our interactions with all stakeholders. We believe a safe organization is a successful organization and we prioritize personal and process safety across the company.

Our Executive Leadership Team (ELT) and Board of Directors help to set our HCM strategy and drive accountability for meaningful progress. Our HCM programs are managed by our human resources function with support from business leaders across the company and are regularly reviewed by the Board of Directors. Our efforts are built around three pillars: a compelling culture, attracting a world-class workforce and valuing our people.

At year-end 2025, we had approximately 9,900 employees in 14 countries. A table of 2025 employees by country is shown below:

2025 Employees by Country	Percent of Total
U.S.	62 %
Norway	16
Canada	8
Equatorial Guinea	4
Malaysia	3
Other Global Locations	7
Total	100 %

A Compelling Culture
How we do our work is what sets us apart and drives our performance. As our industry evolves, we need a workforce equipped to address new opportunities and challenges. Our success depends on our people. Effectively engaging, developing and rewarding our employees is a priority for us. Together, we deliver strong performance while embracing our core cultural attributes.

Health, Safety and Environment
Our HSE organization sets expectations and provides tools and assurance to our workforce to promote and achieve HSE excellence. We manage and assure ConocoPhillips HSE policies, standards and practices, to help ensure business activities are consistently safe, healthy and conducted in an environmentally and socially responsible manner across the globe. Each business unit manages its local operational risks with particular attention to process safety, occupational safety and environmental and emergency preparedness risks. Objectives, targets and deadlines are set and tracked annually to drive strong HSE performance. Progress is tracked and reported to our ELT and the Board of Directors. Corporate HSE audits are conducted on business units and staff groups to ensure conformance with ConocoPhillips HSE policies, standards and practices. If improvement actions are identified, they are tracked to completion.

We continuously look for ways to operate more safely, efficiently and responsibly. We focus on reducing human error by emphasizing interaction among people, equipment and work processes. We believe our HSE policies such as Life Saving Rules, Process Safety Fundamentals, safety procedures and our stop work policy can reduce the likelihood and severity of unexpected incidents. We conduct thorough investigations of all serious incidents to understand the root cause and share lessons learned globally to improve our facility designs, procedures, training and maintenance programs. It is important that we drive an HSE culture of continuous learning and improvement, refine our existing HSE processes and tools and enhance our commitment to safe, efficient and responsible operations.

Attracting a World-Class Workforce
Our continued success requires a skilled global workforce. Our SPIRIT Values help to cultivate an inclusive environment where everyone can contribute, promoting innovation and leading to better business outcomes. This helps us attract a workforce equipped to address new opportunities and challenges that we face in a complex industry. We recruit experienced hires to help us sustain a broad range of expertise and partner with universities and organizations to create a pipeline of early-career talent. We strive to ensure fair and consistent practices in our recruitment process and conduct talent assessments to meet our business needs.

Valuing our People

Employee Engagement and Development

We engage and develop our workforce through on-the-job learning, formal training, ongoing feedback, coaching and mentoring. Additionally, we use a performance management program focused on merit, objectivity, credibility and transparency. The program includes broad stakeholder feedback, real-time monetary and non-monetary recognition and a formal "how" rating to assess behavior to ensure they align with our SPIRIT Values.

Skills-based Talent Management Teams (TMTs) guide employee development and career progression, help identify workforce planning needs and assess the availability of critical skill sets. Succession planning is a top priority for management and the Board of Directors to ensure talent readiness and availability for leadership roles.

We measure and assess employee satisfaction and engagement through periodic employee engagement surveys. Our leaders review survey feedback to guide priorities and goals.

Compensation, Benefits and Well-Being

We offer competitive, performance-based compensation packages and have global, equitable pay practices. Our compensation programs generally include base pay, the annual Variable Cash Incentive Program (VCIP) and, for eligible employees, the Restricted Stock Unit (RSU) program. Our retirement and savings plans support employees' financial futures and are competitive within local markets.

We routinely benchmark our global compensation and benefits programs to ensure they are competitive and meet the needs of our employees. We provide flexible work schedules and competitive time off, including parental leave in many locations. We also provide coverage for disability support, elder care and childcare, including onsite childcare, where access locally is a challenge.

General

The environmental information contained in Management’s Discussion and Analysis of Financial Condition and Results of Operations beginning on page *53* under the caption "Environmental" and beginning on page *55* under the caption “Climate Change” is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2025 and those expected for 2026 and 2027.

Website Access to SEC Reports

Our internet website address is *www.conocophillips.com.* Information contained on our internet website is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC’s website at *www.sec.gov*.

Item 1A. Risk Factors

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. These risk factors are not the only risks we face. Our business could also be affected by additional risks and uncertainties not currently known to us or that we currently consider to be immaterial. If any of these risks or other risks that are yet unknown or currently considered immaterial were to occur, our business, operating results and financial condition, as well as the value of an investment in our common stock, could be materially and adversely affected.

Risks Related to Our Industry

Our operating results, our ability to execute on our strategy and the carrying value of our assets are exposed to the effects of volatile commodity prices or prolonged periods of low commodity prices.

Among the most significant factors impacting our revenues, operating results and future rate of growth are the sales prices for crude oil, bitumen, LNG, natural gas and NGLs. These prices are tied to market prices that can fluctuate widely due to factors beyond our control. For example, over the course of 2025, WTI crude oil prices ranged from a high of $80 per barrel in January to a low of $55 per barrel in December. Given the volatility in the drivers of commodity prices and our associated realizations, the worldwide political and economic environment, including potential economic slowdowns or recessions, unexpected shocks to supply and demand, or increased uncertainty generated by armed hostilities and geopolitical tension and escalations in various oil-producing regions around the globe, prices for crude oil, bitumen, LNG, natural gas and NGLs may continue to be volatile.

Prolonged periods of low commodity prices could have a material adverse effect on our revenues, operating income, cash flows and liquidity, and may also affect the amount of dividends we elect to declare and pay on our common stock and the amount of shares we elect to acquire as part of our share repurchase program and the timing of such repurchases.

Lower prices may also limit the amount of reserves we can produce economically, thus adversely affecting our proved reserves and reserve replacement ratio and accelerating the reduction in our existing proved reserve levels as we continue production from upstream fields. Prolonged depressed prices may affect strategic decisions related to our operations, including decisions to reduce capital investments or curtail operated production.

Significant reductions in crude oil, bitumen, LNG, natural gas and NGLs prices could also require us to reduce our capital expenditures, impair the carrying value of our assets or discontinue the classification of certain assets as proved reserves. Although it is not reasonably practicable to quantify the impact of any future impairments or estimated change to our unit-of-production rates at this time, our results of operations could be adversely affected as a result.

If we do not successfully develop resources, the scope of our business will decline, and our financial condition and results of operations may be adversely affected.

As we produce crude oil, bitumen, natural gas and NGLs from our existing portfolio, the amount of our remaining reserves declines. If we do not successfully replace the resources we produce with good prospects for future organic development or through acquisitions, our business will decline. In addition, our ability to successfully develop our reserves depends on our achievement of a number of operational and strategic objectives, some aspects of which are beyond our control, including navigating political and regulatory challenges to obtain and renew rights to develop and produce hydrocarbons; reservoir optimization; bringing long-lead time, capital intensive projects to completion on budget and on schedule; and efficiently and profitably operating mature properties. If we are not successful in developing the resources in our portfolio, our financial condition and results of operations may be adversely affected.

The exploration and production of oil and gas is a highly competitive industry.

The exploration and production of crude oil, bitumen, natural gas and NGLs is a highly competitive business. We compete with private, public and state-owned companies in all facets of the exploration and production business, including locating, acquiring and developing new sources of supply and producing crude oil, bitumen, natural gas and NGLs in an efficient, cost-effective manner. In addition, we anticipate the oil and gas industry will face additional competition from alternative fuels. We must also compete for the materials, equipment, services, employees and other personnel (including geologists, geophysicists, engineers and other specialists) necessary to conduct our business. If we are not successful in any facet of this competition, our financial condition and results of operations may be adversely affected.

Our ability to successfully execute on our plans to reduce operational GHG emissions intensity is subject to a number of risks and uncertainties and such reductions may be costly and challenging to achieve.

Our framework for managing climate-related business risk is set out in our Climate-related Risk Strategy, which describes our strategic flexibility, approach to reducing Scope 1 and 2 emissions intensity, technology choices and engagement efforts. Among other things, we have set near- and medium-term GHG intensity reduction targets, as well as targets around flaring and methane. Our ability to achieve the stated targets, goals and ambitions within the Climate-related Risk Strategy's framework is subject to a number of risks and uncertainties beyond our control, including government policies and markets, acceptance of carbon capture technologies, development of markets and potential permitting and regulatory changes, all of which may impair our ability to execute on current or future plans. In addition, the pace of development of effective emissions measurement and abatement technologies, and the actual pace of deployment may be inadequate, or the technologies actually developed may be insufficient to allow us to achieve our stated targets, goals and ambitions.

Furthermore, executing our Climate-related Risk Strategy could be costly, is likely to encounter unforeseen obstacles, will proceed at varying paces and may be accomplished in a manner that we cannot predict at this time. We expect to be required to purchase emission credits and/or offsets in the future. There may be an insufficient supply of offsets, and we could incur increasingly greater expenses related to our purchase of such offsets. Even if we are able to acquire an adequate amount of such offsets at satisfactory prices, investors, regulators or other third parties may not perceive this practice as an acceptable means of achieving our operational emission reduction targets. As advanced technologies are developed to accurately measure emissions, we may be required to revise our emissions estimates and reduction goals or otherwise revise aspects of our Climate-related Risk Strategy. We may be adversely affected and potentially need to reduce economic end-of-field life of certain assets and impair associated net book value due to the emissions intensity of some of our assets. Even if we meet our goals, our efforts may be characterized as insufficient.

We continue to evaluate low carbon opportunities for potential future investment in support of our operational emission reduction targets. Such potential investments may expose us to numerous financial, legal, operational, reputational and other risks and may not ultimately contribute materially to operational emissions reductions. The success of any such investment will depend in part upon the cooperation of government agencies, the support of stakeholders, the development of relevant markets for low carbon fuels, our ability to research and forecast potential investments, willingness of industry partners to collaborate and our ability to apply our existing strengths and expertise to new technologies, projects and markets.

Estimates of crude oil, bitumen, natural gas and NGL reserves are imprecise and may be subject to revision, and any material change in the factors and assumptions underlying our estimates of crude oil, bitumen, natural gas and NGL reserves could impair the quantity and value of those reserves.

Our proved reserve information included in this annual report represents management’s best estimates based on assumptions, as of a specified date, of the volumes to be recovered from underground accumulations of crude oil, bitumen, natural gas and NGLs. Such volumes cannot be directly measured, and the estimates and underlying assumptions used by management are subject to substantial risk and uncertainty. Any material changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported or could cause us to incur impairment expenses on property associated with the production of those reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation and commodity prices. For more information on estimates used, see the *"Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Our business may be adversely affected by price controls; government-imposed limitations on production or exports of crude oil, bitumen, LNG, natural gas and NGLs; or the unavailability of adequate gathering, processing, compression, transportation, and pipeline facilities and equipment for our production of crude oil, bitumen, natural gas and NGLs.

As discussed herein, our operations are subject to extensive governmental regulations across numerous jurisdictions. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil, bitumen, natural gas and NGLs wells below actual production capacity. Similarly, in response to increased domestic energy costs, circumstances determined to be in the economic or other interest of the country, or a declared national emergency, governments could restrict the export or import of our products which would adversely impact our business. For example, in January 2024, in response to concerns from environmental groups, the U.S. announced a temporary pause on new authorizations of certain LNG exports. The pause was subsequently lifted in January 2025. This pause and other difficulties in the regulatory approval processes may have an extended adverse impact on our global LNG business. Furthermore, because legal requirements are frequently changed and subject to interpretation, we cannot predict whether future restrictions on our business may be enacted or become applicable to us.

Our ability to sell and deliver the crude oil, bitumen, LNG, natural gas and NGLs that we produce also depends on the availability, proximity and capacity of gathering, processing, compression, transportation and pipeline facilities and equipment, as well as any necessary diluents to prepare our crude oil, bitumen, LNG, natural gas and NGLs for transport. The facilities, equipment and diluents we rely on may be temporarily unavailable to us due to market conditions, extreme weather events, permitting delays and other regulatory matters, mechanical reasons or other factors or conditions, many of which are beyond our control. In addition, in certain newer plays, the capacity of necessary facilities, equipment and diluents may not be sufficient to accommodate production from existing and new wells, and construction and permitting delays, permitting costs and regulatory or other constraints could limit or delay the construction, manufacture or other acquisition of new facilities and equipment. If any facilities, equipment or diluents, or any of the transportation methods and channels that we rely on become unavailable for any period of time, we may incur increased costs to transport our crude oil, bitumen, LNG, natural gas and NGLs for sale; we may be forced to curtail our production of crude oil, bitumen, natural gas or NGLs, or we may not be able to meet all the objectives in our Climate-related Risk Strategy, such as reducing routine flaring.

Our ability to manage risk or influence outcomes in joint ventures may be constrained.

We conduct many of our operations through joint ventures in which another joint venture partner is the operator or we may not have majority control. In these cases, the economic, business, or legal interests or goals of the operator or the voting majority may be inconsistent with ours, and we may not be able to influence the decision making or outcomes to align with our interests or goals. Failure by an operator or a voting majority, with whom we have a joint venture interest, to adequately manage the risks associated with any operations could have an adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

Our operations are subject to hazards and risks that require significant and continuous oversight.

Our operations are subject to a variety of hazards and risks that require significant and continuous oversight, such as the monitoring, prevention or mitigation of or protection from explosions; fires; product spills; severe weather; geological events; global health crises, such as epidemics and pandemics; labor disputes; geopolitical tensions and escalations; armed hostilities; terrorist or piracy attacks; sabotage; civil unrest or cyberattacks. Our operations are subject to additional hazards concerning exposure to and potential release of pollutants and toxic substances, as well as other environmental hazards and risks. For example, offshore activities may pose incrementally greater technological challenges, operating risks and potential for adverse consequences from operational failures because of complex subsurface conditions such as higher reservoir pressures, water depths and metocean conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation. Our business and operations may be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any of these hazards and risks or any other major crisis or if we are unable to efficiently restore or replace affected operational components and capacity. Countermeasures to address global health crises, epidemics or pandemics may result in reduced demand for our products; disruptions to our supply chain, the global economy or financial or commodity markets; disruptions in our contractual arrangements with our service providers, suppliers and other counterparties; failures by our suppliers, contract manufacturers, contractors, joint venture partners and external business partners to meet their obligations to us; reduced workforce productivity; and voluntary or involuntary curtailments. Further, our insurance may not be adequate to compensate us for all resulting losses described above, and the cost to obtain adequate coverage may increase for us in the future or may not be available.

In addition, although we design and operate our business operations to accommodate expected climatic conditions, to the extent there are significant changes in the earth's climate, such as more severe or frequent weather conditions in the markets where we operate or the areas where our assets reside, we could incur increased expenses, our operations and supply chain could be adversely impacted and demand for our products could fall.

Any of these factors, or other cascading effects of such factors, could materially increase our costs; negatively impact our revenues or ability to implement and advance our Climate-related Risk Strategy; and damage our financial condition, results of operations, cash flows and liquidity position. The full extent and duration of any such impacts cannot be predicted at this time because of the lack of certainty surrounding their sources, causes and outcomes.

Legal and Regulatory Risks

We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations.

Our business is subject to numerous laws and regulations relating to the protection of the environment, which are expected to continue to have an increasing impact on our operations. For a description of the most significant of these environmental laws and regulations, see the *"Contingencies—Environmental", "—Climate Change"* and *"—Company Response to Climate-Related Risks"* sections of Management's Discussion and Analysis of Financial Condition and Results of Operations. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- Permits required in connection with exploration, drilling, production and other activities, including those issued by national, subnational and local authorities;
- The discharge of pollutants into the environment;
- Emissions into the atmosphere, such as nitrogen oxides, sulfur dioxide, mercury and GHG emissions, including methane and carbon dioxide;
- Carbon taxes;
- The handling, use, storage, transportation, disposal and cleanup of hazardous materials and hazardous and nonhazardous wastes;
- The dismantlement, abandonment and restoration of historic properties and facilities at the end of their useful lives; and
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and unconventional plays.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. In addition, to the extent these expenditures are assumed by a buyer as a result of a disposition, it may result in our incurring substantial costs if the buyer is unable to satisfy these obligations. Any actual or perceived failure by us to comply with existing or future laws, regulations and other requirements could result in administrative or civil penalties, criminal fines, other enforcement actions or third-party litigation against us. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products, our business, financial condition, results of operations and cash flows in future periods, as well as our ability to implement and advance our Climate-related Risk Strategy could be adversely affected.

Existing and future laws, regulations and internal initiatives relating to global climate change, such as limitations on GHG emissions or provisions aimed at reducing such emissions, may impact or limit our business plans, result in significant expenditures, promote alternative uses of energy or reduce demand for our products.

Continuing political and societal attention to the issue of global climate change has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit GHG emissions, such as cap and trade regimes, specific emission standards, carbon taxes, restrictive permitting, increased fuel efficiency standards and incentives or mandates for renewable and alternative energy. Although we may support the intent of legislative and regulatory measures aimed at addressing climate-related risks, the specifics of how and when they are enacted could result in a material adverse effect to our business, financial condition, results of operations and cash flows in future periods as well as our ability to implement and advance our Climate-related Risk Strategy.

For example, in 2024, New York and Vermont passed legislation seeking to hold certain energy companies financially responsible for state climate change mitigation and adaptation measures, following the "polluter pays" model of existing Superfund laws. This responsibility may include paying into a fund for infrastructure repairs and recovery from extreme weather events that would otherwise be covered by the government. While only two U.S. states have enacted such laws to date, other states have introduced similar measures, and it is likely that more states will consider a similar approach. Compliance with such legislation may expose us to significant additional liabilities. Additionally, legislation has been introduced in certain U.S. states that would provide Attorneys General, insurers and individuals a right to recover against certain energy companies for alleged climate change impacts. Should such legislation become law, we may be exposed to additional, significant liabilities.

Furthermore, in December 2023, the EPA published a final rule that revises the regulations governing, among other things, the emission of methane and volatile organic compounds from new oil and gas production facilities and emission guidelines for states to use when revising Clean Air Act implementation plans to limit methane emissions from existing oil and gas facilities. However, in 2025 the EPA moved to dismantle some climate-related regulations (e.g. delaying compliance deadlines for methane standards and proposing to eliminate most obligations under the Greenhouse Gas Reporting Program). These policy swings create additional uncertainty for companies who need to plan for operations that will endure through administrations. These regulatory changes may also complicate our ability to access non-operated or joint venture emissions data to complete our inventory of emissions.

Additionally, international climate initiatives, such as the United Nations Conference of the Parties summits, continue to shape the global response to climate change. These summits can lead to commitments from numerous countries to meet the objectives of agreements like the Paris Agreement, through adopting country level regulation to reduce greenhouse gas emissions.

The implementation of current agreements and regulatory or judicial measures, as well as any future agreements or measures addressing climate change and GHG emissions, may adversely increase our capital and operating expenses, impact the demand for our products, impose taxes on our products or operations, or require us to purchase emission credits or reduce emissions of GHGs from our operations. As a result, we may incur substantial capital expenditures and compliance, operating, maintenance and remediation costs, any of which may have an adverse effect on our business and results of operations.

For more information on legislation or precursors for possible regulation relating to global climate change that affect or could affect our operations and a description of the company's response, see the *"Contingencies—Climate Change”* and *"—Company Response to Climate-Related Risks"* sections of Management’s Discussion and Analysis of Financial Condition and Results of Operations.

Broader investor and societal attention to and efforts to address global climate change may limit who can do business with us or our access to financial markets and could subject us to litigation.

Attention to global climate change has also resulted in pressure from and upon stockholders, financial institutions and other financial market participants to potentially limit or discontinue investments, insurance and funding to oil and gas companies. For example, a significant number of financial institutions have pledged to meet the goal of net zero by 2050, as well as setting interim targets for 2030 or earlier. While these targets do not prohibit financial sector stakeholders from doing business with oil and gas companies, stakeholders may self-impose limits. Conversely, we also face pressure from some in the investment community and certain public interest groups to limit the focus on ESG in our decision-making, arguing that ESG considerations do not relate to financial outcomes. As public pressure continues to mount on the financial sector, our costs of capital may increase.

Furthermore, attention to global climate change has resulted in an increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business. Beginning in 2017 and continuing through 2025, cities, counties, governments and other entities in several states/territories in the U.S. have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change impacts. Additional lawsuits with similar allegations are expected to be filed by governmental entities. In 2025, a putative class action was filed against oil and gas companies, including ConocoPhillips, seeking to hold energy companies liable for increased home insurance premiums allegedly due to climate change losses. The amounts claimed by plaintiffs are unspecified and the legal and factual issues involved in these cases are unprecedented. We believe these lawsuits are factually and legally meritless and are an inappropriate vehicle to address the challenges associated with climate change, and we will vigorously defend against such lawsuits. The ultimate outcome and impact to us cannot be predicted with certainty, and we expect to incur substantial legal costs associated with defending these and similar lawsuits in the future. We could also receive lawsuits alleging a failure or lack of diligence to meet our publicly stated ESG goals or alleging misrepresentation related to our ESG activity.

Political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Actions of the U.S., state, local and foreign governments, through sanctions, tax, tariffs and other legislation, executive orders and commercial restrictions, could reduce our operating profitability both in the U.S. and abroad. In certain locations, restrictions on our operations; leasing restrictions; special taxes or tax assessments; tariffs; and payment transparency regulations that could require us to disclose competitively sensitive information or might cause us to violate non-disclosure laws of other countries have been imposed or proposed by governments or certain interest groups. In addition, we may face regulatory changes in the U.S. including, but not limited to, the enactment of tax law changes that adversely affect the fossil fuel industry, new methane emissions standards, requirements restricting or prohibiting flaring and subsurface water disposal, more stringent environmental impact studies and reviews and policies inhibiting or curtailing LNG or crude oil exports. Similar regulatory shifts, including attendant higher costs and market access constraints, may also occur in international jurisdictions in which we currently operate or seek to operate.

Hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations, has historically attracted political and regulatory scrutiny. A range of local, state, federal and national laws and regulations currently govern, constrain or prohibit hydraulic fracturing in some jurisdictions. New or more stringent permitting, disclosure or other regulatory requirements on hydraulic fracturing or other oil and natural gas operations, including subsurface water disposal, could result in increased costs, operating restrictions or operational delays or could limit the ability to develop oil and natural gas resources.

In addition, certain interest groups have also proposed ballot initiatives, contested lease sales and challenged project permits, for example, to restrict oil and natural gas development generally as well as specific projects, including the Willow project in Alaska. In the event that ballot initiatives, local, state, or national restrictions or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development or production activities. Such compliance costs and delays, curtailments, limitations or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, liquidity and ability to implement and advance the Climate-related Risk Strategy.

Political and economic factors in international markets could have a material adverse effect on us.

Approximately 29 percent of our hydrocarbon production was derived from production outside the U.S. in 2025, and 31 percent of our proved reserves, as of December 31, 2025, were located outside the U.S. We are subject to risks associated with our operations in foreign jurisdictions and international markets, including changes in foreign governmental policies relating to crude oil, bitumen, LNG, natural gas or NGLs pricing and taxation; other regulatory or economic developments (including the macro effects of U.S. and international trade policies and disputes); disruptive geopolitical conditions such as recent conflict escalation in the Middle East and Eastern Europe; and international monetary and currency rate fluctuations. Restrictions on production of oil and gas could increase to the extent governments view such measures as a viable approach for pursuing national and global energy security and climate policies. In addition, some countries where we operate lack a fully independent judiciary system. This, coupled with changes in foreign law or policy, results in a lack of legal certainty that exposes our operations to increased risks, including increased difficulty in enforcing our agreements in those jurisdictions and increased risks of adverse actions by local government authorities, such as expropriations. Actions by host governments, such as the expropriation of our oil assets by the Venezuelan government, have affected operations significantly in the past and may continue to do so in the future.

In addition, the U.S. government has the authority to prevent or restrict us from doing business in foreign jurisdictions or with certain parties. These restrictions and similar restrictions imposed by foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various jurisdictions. Diplomatic relations or policies between the U.S. government and one or more foreign jurisdictions may increase our expenses or impair our ability to collect awards in legal actions against such foreign jurisdictions. Changes in domestic and international policies and regulations may also restrict our ability to obtain or maintain licenses or permits necessary to operate in foreign jurisdictions, including those necessary for drilling and development of wells. Similarly, the declaration of a “climate emergency” could result in actions to limit exports of our products and other restrictions.

Any of these actions could adversely affect our business or operating results, including our ability to implement and advance the Climate-related Risk Strategy.

Other Risk Factors Facing our Business or Operations

We may need additional capital in the future, and it may not be available on acceptable terms or at all.

We have historically relied primarily upon cash generated by our business to fund our operations and strategy; however, we have also relied from time to time on access to the capital markets for funding. There can be no assurance that additional financing will be available in the future on acceptable terms or at all. In addition, although we anticipate we will be able to repay our existing indebtedness when it matures or in accordance with our stated plans, there can be no assurance we will be able to do so. Our ability to obtain additional financing or refinance our existing indebtedness when it matures or in accordance with our plans, will be subject to a number of factors, including market conditions, our operating performance, investor sentiment, risks impacting financial institutions and the credit markets more broadly and financial institution policies regarding the oil and gas industry. If we are unable to generate sufficient funds from operations or raise additional capital for any reason, our business could be adversely affected.

In addition, we are regularly evaluated by the major rating agencies based on a number of factors, including our financial strength and conditions affecting the oil and gas industry generally. We and other industry companies have had our ratings reduced in the past due to negative commodity price outlooks. These major rating agencies are now considering ESG attributes when assessing credit profiles. While these assessments have limited impact today, they have the potential to pressure credit ratings over time. Any downgrade in our credit rating or announcement that our credit rating is under review for possible downgrade could increase the cost associated with any additional indebtedness we incur.

Our business may be adversely affected by deterioration in the credit quality of, or defaults under our contracts with, third parties with whom we do business.

The operation of our business requires us to engage in transactions with numerous counterparties operating in a variety of industries, including other companies operating in the oil and gas industry. These counterparties may default on their obligations to us as a result of operational failures or a lack of liquidity, or for other reasons, including bankruptcy. Market speculation about the credit quality of these counterparties, or their ability to continue performing on their existing obligations, may also exacerbate any operational difficulties or liquidity issues they are experiencing. Any default by any of our counterparties may result in our inability to perform our obligations under agreements we have made with third parties or may otherwise adversely affect our business or results of operations. In addition, our rights against any of our counterparties as a result of a default may not be adequate to compensate us for the resulting harm caused or may not be enforceable at all in some circumstances. We may also be forced to incur additional costs as we attempt to enforce any rights we have against a defaulting counterparty, which could further adversely impact our results of operations.

Our ability to execute our capital return program is subject to certain considerations.

Ordinary dividends are authorized and determined by our Board of Directors in its sole discretion and depend upon a number of factors, including:

- Cash available for distribution;
- Our results of operations and anticipated future results of operations;
- Our financial condition, especially in relation to anticipated future capital needs;
- The level of distributions paid by comparable companies;
- Our operating expenses; and
- Other factors our Board of Directors deems relevant.

We paid a quarterly ordinary dividend to our shareholders in each quarter of 2025. Our Board may determine not to pay a dividend in a quarter or may cease declaring a dividend at any time.

Additionally, as of December 31, 2025, up to $25.7 billion of share repurchase authority remained. Our share repurchase program does not obligate us to acquire a specific number of shares during any period, and our decision to commence, discontinue or resume repurchases in any period will depend on the same factors that our Board of Directors may consider when declaring dividends, among other factors. In the past, we have suspended our share repurchase program in response to market downturns, including as a result of the oil market downturn that began in early 2020, and we may do so again in the future.

Any downward revision in the amount of our ordinary dividend or the volume of shares we purchase under our share repurchase program could have an adverse effect on the market price of our common stock.

There are substantial risks with any acquisitions or divestitures we have completed or that we may choose to undertake.

We regularly review our portfolio and pursue growth through acquisitions and seek to divest noncore assets or businesses. We may not be able to complete these transactions on favorable terms, on a timely basis, or at all. Even if we do complete such transactions, our cash flow from operations may be adversely impacted or otherwise the transactions may not result in the benefits anticipated due to various risks, including, but not limited to (i) the failure of the acquired assets or businesses to meet or exceed expected returns, including risk of impairment; (ii) the inability to dispose of noncore assets and businesses on satisfactory terms and conditions; and (iii) the discovery of unknown and unforeseen liabilities or other issues related to any acquisition for which contractual protections are inadequate or we lack insurance or indemnities, including environmental liabilities, or with regard to divested assets or businesses, claims by purchasers to whom we have provided contractual indemnification. In addition, we may face difficulties in integrating the operations, technologies, products and personnel of any acquired assets or businesses.

Our technologies, systems and networks are subject to cybersecurity threats.

Our business is faced with growing cybersecurity threats as we increasingly rely on digital technologies across our business. Cybersecurity risks to our business, including our suppliers, third-party service providers, contractors, joint venture partners and external business partners, include but are not limited to:

- Unauthorized access to, or control of or disclosure of sensitive information about our business and our employees;
- Compromise of our data or systems, including corruption, sabotage, encryption or acts that otherwise render our data or systems unusable (or those of third parties with whom we do business, including third-party cloud and information technology (IT) service providers);
- Theft or manipulation of our proprietary information;
- Ransom;
- Extortion;
- Threats to the security of our facilities and infrastructure; and
- Cyber terrorism.

In addition, we have exposure to cybersecurity risks where our data and proprietary information are collected, hosted, and/or processed by third-party cloud and service providers. In addition, many of our vendors, including suppliers that are closely integrated into our business, have been victims of cybersecurity attacks that have accessed and exfiltrated information from their systems. Our risks may be exacerbated by a delay or failure to detect a cybersecurity incident or to understand the full extent of such incident notwithstanding our risk management processes and controls. We face risks associated with new and ever-increasing phishing techniques, hidden malware, as well as risks associated with electronic data proliferation and technology digitization. We also face increased risk with the increased sophistication of generative artificial intelligence capabilities, which may improve or expand the existing capabilities of cybercriminals described above in a manner we cannot predict at this time.

Our increasing reliance on IT in our production, distribution and marketing systems may allow cybersecurity threats to disrupt our oil and gas operations, both domestically and abroad.

If our data, IT, operational technology (OT), including industrial control and supervisory control and data acquisition (SCADA) systems were to be breached, damaged or disrupted due to a cybersecurity incident or cyber-attack (directly, indirectly through third parties or through the IT networks, servers, software, or infrastructure on which they rely), we could be subject to serious negative consequences. These consequences could include physical damage to production, distribution or storage assets; delay or prevention of delivery to markets; disruption or prevention of accurate accounting for production and settlement of transactions; negative impacts on public health, safety, the environment, economic security, or national security; financial impacts; business interruption; reputational damage; loss of employee, supplier, contractor, partner and/or public trust; reimbursement or other costs; increased compliance costs; regulatory investigations; litigation exposure and legal liability or regulatory fines; penalties or other external intervention.

Although we have business continuity plans in place, our operations may be adversely affected by significant and widespread disruption to our systems and infrastructure that support our business. If we seek insurance against cybersecurity risks, it may be limited by the availability and increasing expense of sufficient coverage.

For additional information regarding our cybersecurity risk management, strategy and governance, *see Item 1C. Cybersecurity*.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Cybersecurity Risk Management and Strategy

Cybersecurity Risk Assessment and Management

We take a multilayered approach to cybersecurity risk management and strategy. Our IT/OT Security Program integrates administrative, technical, and physical controls against evolving cybersecurity threats, and includes enterprise IT and OT security architecture, cybersecurity operations, data privacy and governance, supply chain security, and governance, risk, and compliance. Additionally, it is designed to identify, assess, and manage cybersecurity risks and protect the confidentiality, integrity, and availability of our data, IT, and OT.

Cybersecurity is a component of our IT/OT Security Program, which we periodically review and adapt to respond to new and evolving circumstances, cybersecurity threats and regulations. We evaluate security, privacy, and resiliency risks, including those related to cybersecurity, in our overall Enterprise Risk Management (ERM) program's annual risk assessment process. This annual risk assessment process takes into account broader risks based on likelihood, potential consequences, and mitigations, such as operational and economic impact; health, safety and environmental impact; and reputational and financial implications. This risk assessment is discussed with members of the ELT, Audit and Finance Committee (AFC) of the Board of Directors, and Board of Directors on at least an annual basis.

We consult recognized security frameworks, such as the National Institute of Standards and Technology Cybersecurity Framework to organize, improve, and assess our IT/OT Security Program to manage and reduce cybersecurity risk. We deploy, configure, and maintain various technologies designed to enforce security policies, detect and protect against cybersecurity threats, and help safeguard IT and OT assets. We operate a Cybersecurity Operation Center (CSOC) to ingest threat intelligence, monitor cybersecurity threats, coordinate incident response resources and manage response times.

Our Global Computer Security Incident Response Plan (CSIRP) establishes the framework for our response to cybersecurity incidents. Under the CSIRP, cybersecurity incidents are escalated based on a defined incident categorization to the Chief Information Security Officer (CISO) and senior leaders, including the Chief Digital & Information Officer (CD&IO), General Counsel, Chief Financial Officer, and other cybersecurity program stakeholders, such as the AFC and/or the full Board of Directors. We also conduct incident response exercises at least annually, which are facilitated by internal team members and, in some instances, with assistance from third-party experts.

Physical controls are designed to work in conjunction with digital and cybersecurity controls to help protect the company's IT and OT assets from physical threats. Our Chief Security Officer is responsible for a physical security program including site plans, cameras, security systems monitoring, and access control and badging systems to manage physical security risks.

Our governing policies, standards and procedures create a structured approach to managing cybersecurity risk. Information security requirements for employees, contractors and partners are detailed in the ConocoPhillips Information Security & Protection Policy. Our workforce is required to complete information security training annually, and we periodically communicate ways to recognize and avoid cybersecurity threats to our workforce.

Engagement of Third Parties

We engage third-party cybersecurity consultants and experts to supplement staffing of our CSOC, as well as to help us assess, validate, and enhance our security practices, including conducting cybersecurity maturity assessments, vulnerability assessments and penetration tests.

As part of the cybersecurity incident response process described above, we engage third-party experts as needed to support incident response, such as external legal advisors, cybersecurity forensic firms and other specialists.

Third-Party Service Provider Risk Management

Our third-party risk management process is designed to identify, assess, and mitigate risks associated with third-party service providers, including cybersecurity risks. An initial assessment is conducted to assess the cybersecurity risks associated with a third-party provider based on various criteria, such as whether the third-party provider has access to our network, data, and information systems. Third-party providers that are identified through the initial assessment as warranting further review are subject to additional risk assessment. In parallel, we have designed a contracting process to mitigate cybersecurity risks by specifying the rights and responsibilities of the parties.

Risks from Material Cybersecurity Threats

While we are subject to ongoing cybersecurity threats, we do not believe that the risks from previous threats have materially affected or are reasonably likely to materially affect the company, including our business strategy, results of operations or financial condition. Nevertheless, we recognize cybersecurity threats are on-going and evolving, and our program is designed to identify and manage those threats. *See Item 1A. Risk Factors—Our technologies, systems and networks are subject to cybersecurity threats* for more information on our risks relating to our technologies, systems, and networks.

Cybersecurity Governance

Management's Role

A dedicated CISO leads the IT/OT Security Team and is responsible for our cybersecurity risk management and strategy. The CISO has over 20 years of experience in security, of which 18 years is specific to cybersecurity and has served as a CISO since 2013, having joined ConocoPhillips as CISO in 2022. The CISO holds a master’s degree and is a Certified Information Security Professional. The CISO reports to the CD&IO, who holds a master’s degree in information technology and has served as Chief Information Officer/Chief Technology Officer and various roles in information technology for over 29 years. The CD&IO reports to the Executive Vice President, Global Operations and Technical Functions. This management team assesses and manages risks associated with cybersecurity.

Board of Directors' Oversight

While our cybersecurity management team is responsible for the day-to-day assessment and management of material risks from cybersecurity threats, the ConocoPhillips Board of Directors has oversight responsibility for our ERM program and the individual risk management programs comprising our ERM program, including cybersecurity risk management. To help maintain effective Board of Directors' oversight across the entire enterprise, the Board of Directors delegates certain elements of its oversight function to individual committees. The AFC assists the Board of Directors in fulfilling its oversight of our ERM program and cybersecurity.

The Board of Directors receives a report on cybersecurity annually, and the AFC receives reports on cybersecurity multiple times a year. For meetings where cybersecurity is not on the formal agenda, the AFC will receive a pre-read that includes cybersecurity updates or discussion topics. During these reviews, management discusses various topics, including information relating to IT/OT Security strategy, program management, cybersecurity risks and threats, and provides briefings on notable cybersecurity attacks, including those relating to third-party service providers, if known. In addition to this regular reporting, significant cybersecurity risks or threats may also be escalated on an as needed basis to the AFC and Board of Directors.

Item 3. Legal Proceedings

We are a defendant in a number of legal and administrative proceedings arising in the ordinary course of business, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were to be decided adversely to ConocoPhillips, we expect there would not be a material effect to our consolidated financial position.

ConocoPhillips has elected to use a $1 million threshold for disclosing certain proceedings arising under federal, state or local environmental laws when a governmental authority is a party. ConocoPhillips believes proceedings under this threshold are not material to ConocoPhillips' business and financial condition. Applying this threshold, there are no such proceedings to disclose for the year ended December 31, 2025. *See Note 9* for information regarding other legal and administrative proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

Information about our Executive Officers

Name	Age*	Current and Prior Positions (up to five years)
Kontessa S. Haynes-Welsh	**51**	**Vice President, Finance and Controller** (since March 2025) Vice President and Treasurer (November 2022 to February 2025) Chief Accounting Officer (March 2021 to October 2022) Assistant Controller (January 2020 to February 2021) Manager, Strategy, Planning and Portfolio Management (June 2018 to January 2020)
Heather G. Hrap	**53**	**Senior Vice President, Human Resources and Real Estate and Facilities Services** (since March 2022) Vice President, Human Resources (January 2019 to February 2022)
Kirk L. Johnson	**50**	**Executive Vice President, Global Operations and Technical Functions** (since June 2025) Senior Vice President, Global Operations (March 2024 to May 2025) Senior Vice President, Lower 48 Assets and Operations (May 2022 to February 2024) Vice President, Corporate Planning and Development (June 2021 to April 2022) President Canada (June 2018 to May 2021)
Ryan M. Lance	**63**	**Chairman of the Board of Directors and Chief Executive Officer** (since May 2012)
Andrew D. Lundquist	**65**	**Senior Vice President, Government Affairs** (since February 2013)
Andrew M. O'Brien	**51**	**Chief Financial Officer and Executive Vice President, Strategy & Commercial** (since June 2025) Senior Vice President, Strategy, Commercial, Sustainability and Technology (March 2024 to May 2025) Senior Vice President, Global Operations (November 2022 to February 2024) Vice President and Treasurer (May 2021 to October 2022) Vice President, Corporate Planning and Development (August 2020 to May 2021)
Nicholas G. Olds	**56**	**Executive Vice President, Lower 48 and Global HSE** (since January 2026) Executive Vice President, Lower 48 (November 2022 to December 2025) Executive Vice President, Global Operations (September 2021 to October 2022) Senior Vice President, Global Operations (August 2020 to September 2021) Vice President, Corporate Planning and Development (June 2018 to August 2020)
Kelly B. Rose	**59**	**Senior Vice President, Legal, General Counsel and Corporate Secretary** (since September 2018)

**On February 17, 2026.*

There are no family relationships among any of the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 12, 2026.

Part II

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

ConocoPhillips' common stock is traded on the NYSE under the symbol "COP."

Cash Dividends Per Share

	2025	2024	
	Ordinary	Ordinary	VROC
First	$ **0.78**	0.58	0.20
Second	**0.78**	0.58	0.20
Third	**0.78**	0.58	0.20
Fourth	**0.84**	0.78	—
Number of Stockholders of Record at January 31, 2026*			46,054

Dividends shown above reflect the quarter in which the dividends were declared.
**In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency listing.*

In the fourth quarter of 2024, we incorporated the prior VROC equivalent payment into our ordinary dividend. The declaration of ordinary dividends and VROC are subject to the discretion and approval of our Board of Directors. The Board has adopted a dividend declaration policy providing that the declaration of any dividends will be determined quarterly. For more information on factors considered when determining the level of these distributions, *see "Item 1A — Risk Factors – Our ability to execute our capital return program is subject to certain considerations."*

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*	Average Price Paid Per Share	Shares Purchased as Part of Publicly Announced Plans or Programs	Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2025	5,084,464	$ 90.02	5,084,464	$ 26,274
November 1-30, 2025	3,277,056	88.28	3,277,056	25,985
December 1-31, 2025	2,963,034	92.81	2,963,034	25,710
	11,324,554		11,324,554	

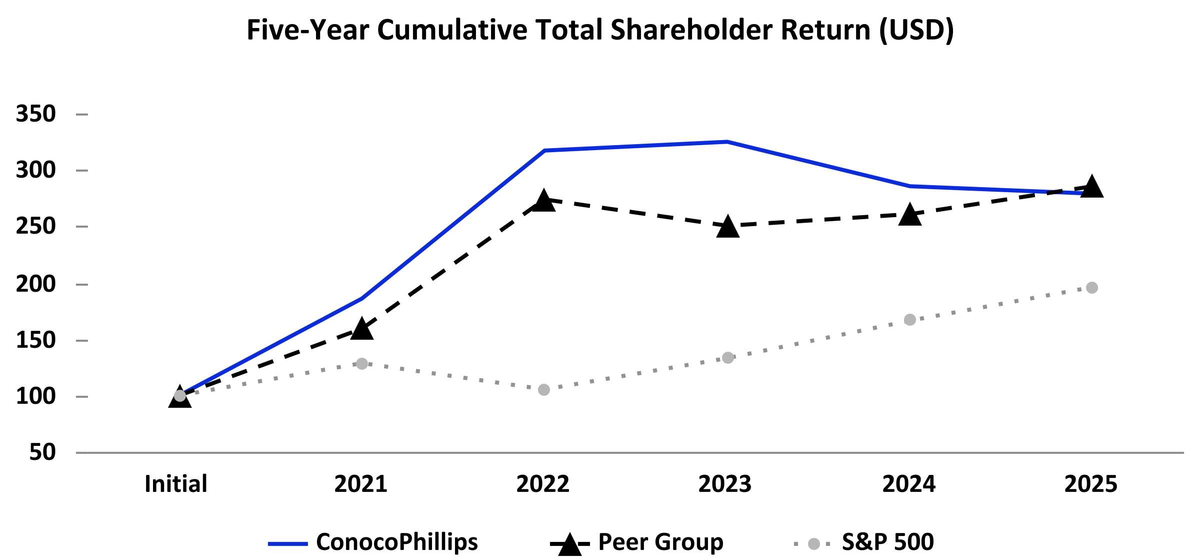
**There were no repurchases of common stock from company employees in connection with the company's broad-based employee incentive plans.*

In late 2016, we initiated our current share repurchase program. In October 2024, our Board of Directors approved an increase from our previous authorization of $45 billion by a total of the lesser of $20 billion or the number of shares issued in our acquisition of Marathon Oil, such that the company is not to exceed $65 billion in aggregate repurchases. As of December 31, 2025, we had repurchased $39.3 billion of shares since 2016. Repurchases are made at management's discretion, at prevailing prices, subject to market conditions and other factors. Except as limited by applicable legal requirements, repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan are held as treasury shares. For more information, *see "Item 1A—Risk Factors – Our ability to execute our capital return program is subject to certain considerations."*

Stock Performance Graph

The following graph shows the cumulative TSR for ConocoPhillips' common stock in each of the five years from December 31, 2020 to December 31, 2025. The graph also compares the cumulative total returns for the same five-year period with the S&P 500 Index and our performance peer group consisting of APA Corporation, Chevron, Devon Energy, Diamondback Energy, EOG Resources, ExxonMobil and Occidental Petroleum weighted according to the respective peer's stock market capitalization at the beginning of each annual period. Due to Chevron's acquisition of Hess Corporation in 2025, Hess Corporation has been removed from our performance peer group and has been excluded from all five years of the peer group performance.

The comparison assumes $100 was invested on December 31, 2020, in ConocoPhillips stock, the S&P 500 Index and ConocoPhillips' peer group and assumes that all dividends were reinvested. The cumulative total returns of the peer group companies' common stock do not include the cumulative total return of ConocoPhillips' common stock. The stock price performance included in this graph is not necessarily indicative of future stock price performance.



Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis is the company's analysis of its financial performance and of significant trends and uncertainties that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "ambition," "anticipate," "believe," "budget," "continue," "could," "effort," "estimate," "expect," "forecast," "goal," "guidance," "intend," "may," "objective," "outlook," "plan," "potential," "predict," "projection," "seek," "should," "target," "will," "would" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 62.

The terms "earnings" and "loss" as used in Management's Discussion and Analysis refer to net income (loss).

Business Environment and Executive Overview

ConocoPhillips is one of the world's leading E&P companies, based on both production and reserves, with operations and activities in 14 countries. Our diverse, low cost of supply portfolio includes resource-rich unconventional plays in North America; conventional assets in North America, Europe, Africa and Asia; global LNG developments; oil sands in Canada; and an inventory of global exploration prospects. Headquartered in Houston, Texas, at December 31, 2025, we employed approximately 9,900 people worldwide and had total assets of $122 billion.

Overview

At ConocoPhillips, we anticipate that commodity prices will continue to be cyclical and volatile, and our view is that a successful business strategy in the E&P industry must be resilient in lower price environments while also retaining upside during periods of higher prices. As such, we are unhedged, remain committed to our disciplined investment framework and continually monitor market fundamentals, including the impacts associated with geopolitical tensions and conflicts, global demand for our products, oil and gas inventory levels, governmental policies, inflation and supply chain disruptions.

Throughout 2025, the price of crude oil has been volatile due to multiple macroeconomic and geopolitical forces which slowed global oil demand growth concurrent with higher oil production from OPEC Plus and other major oil producing countries. We continue to closely monitor the macroeconomic environment, including any impacts from tariffs, and the ongoing market volatility in the energy landscape and across global markets for implications to our business, results of operations and financial condition.

As the global energy industry continues to evolve, we remain committed to creating long-term value for our stockholders. We believe ConocoPhillips plays an essential role in responsibly meeting the global demand for energy, while continuing to deliver competitive returns on and of capital and working to meet our previously established emissions-reduction targets. Our value proposition to deliver competitive returns to stockholders through price cycles is guided by our foundational principles, which consist of maintaining balance sheet strength, providing peer-leading distributions, making disciplined investments, and demonstrating responsible and reliable ESG performance.

Total company production in 2025 was 2,375 MBOED, yielding cash provided by operating activities of $19.8 billion. We invested $12.6 billion into the business in the form of capital expenditures and investments and provided returns of capital to shareholders of $9.0 billion through our ordinary dividend and share repurchases. In 2025, we returned $4.0 billion through the ordinary dividend, inclusive of an increase in December of eight percent to 84 cents per share. In addition, we returned $5.0 billion to shareholders through share repurchases. As of December 31, 2025, we have repurchased $39.3 billion of shares of our authorized share repurchase program since 2016. In February 2026, we declared a first-quarter ordinary dividend of 84 cents per share.

In November 2024, we completed our acquisition of Marathon Oil. In the first half of 2025, we completed the asset integration of Marathon Oil and by year-end 2025 achieved more than $1 billion of synergies on a run-rate basis and approximately $1 billion of one-time benefits. These one-time benefits include $0.5 billion recognized previously upon close of the transaction related to the utilization of foreign tax credits, with the remainder related to cash tax benefits from net operating losses, most of which was recognized in 2025. *See Note 3*.

Separately, in the second half of 2025, we announced incremental cost reductions and margin enhancements of more than $1 billion anticipated on a run-rate basis by year-end 2026. In late 2025, we initiated a restructuring, reducing our overall employee workforce, which in addition to lease operating cost improvements and opportunities in transportation and processing is expected to contribute approximately $0.8 billion in cost reductions. We anticipate the remaining approximately $0.2 billion to be achieved through margin expansion.

In August 2025, we announced a total disposition target of $5 billion by year-end 2026. We disposed of $3.2 billion of assets in 2025 and we expect to meet our $5 billion disposition target by year-end 2026. Completed dispositions to date include the Ursa and Europa fields and Ursa Oil Pipeline Company LLC for net proceeds of $0.7 billion, the Anadarko Basin for net proceeds of $1.2 billion and other noncore Lower 48 and Corporate assets for approximately $1.3 billion. *See Note 3*.

As part of our LNG strategy to build a dynamic portfolio and expand our footprint across the value chain, we have various commercial LNG offtake agreements in North America totaling 10.2 MTPA with offtake commencing between 2026-2031. Furthermore, we currently have a total regasification capacity in Europe of approximately 6.7 MTPA. We continue to progress discussions across all major LNG producing and consuming regions and markets to further add high-quality positions to our portfolio.

Operationally, we remain focused on safely executing the business while also progressing key strategic initiatives. At Willow, we made significant progress and achieved critical milestones, successfully completing our largest winter season. In the Lower 48, we integrated Marathon Oil assets into our portfolio, focusing on operating and capital efficiencies. Internationally, we became the sole operator of the Kebabangan Cluster (KBBC) PSC in Malaysia in January 2025, extending the PSC to 2050 and making KBBC our first operated producing asset in Malaysia. In Canada, we achieved first oil at Surmont Pad 104W-A in December 2025. Additionally, our equity LNG projects continued to advance at NFE and NFS in Qatar and PALNG on the U.S. Gulf Coast.

The relevant provisions of the One Big Beautiful Bill Act (OBBBA), enacted on July 4, 2025, were implemented during the third quarter of 2025. While OBBBA did not have a material effect on our effective tax rate for the quarter, the changes introduced by the legislation impacted our current and deferred tax calculations, with approximately $0.4 billion cash tax benefit recognized in 2025.

Production for 2025 was 2,375 MBOED, representing an increase of 388 MBOED or 20 percent compared to 2024. After adjusting for closed acquisitions and dispositions, production increased by 57 MBOED or 2.5 percent.

Business Environment

The energy industry has historically been subject to volatility in commodity prices, which fluctuate with the global economy's supply and demand for energy. Our profitability, reserves base, reinvestment of cash flows and distributions to shareholders are influenced by these fluctuations. Our foundational principles guide our differential value proposition to deliver competitive returns on and of capital to stockholders through price cycles. Our foundational principles consist of maintaining balance sheet strength, providing peer-leading distributions, making disciplined investments and demonstrating responsible and reliable ESG performance, all of which support strong financial returns and mitigate uncertainty associated with volatile commodity prices.

Balance sheet strength. A strong balance sheet is a strategic asset that provides flexibility through price cycles. We strive to maintain our 'A'-rating, as we did throughout 2025. In 2025, the company retired $0.7 billion principal amount of debt at maturity. We ended the year with cash and cash equivalents and restricted cash of $6.9 billion, short-term investments of $0.5 billion and long-term investments in debt securities of $1.1 billion, maintaining balance sheet strength.

Peer-leading distributions. We believe in delivering value to our shareholders via our return of capital framework, which consists of a growing, sustainable ordinary dividend and share repurchases. This framework is how we plan to return greater than 30 percent of our net cash provided by operating activities to shareholders. In 2025, we returned $4.0 billion to shareholders through our ordinary dividend and $5.0 billion through share repurchases. Our combined dividends and share repurchases of $9.0 billion represented 46 percent of our net cash provided by operating activities.

Disciplined investments. Our goal is to optimize free cash flow by exercising capital discipline, controlling our costs, and safely and reliably delivering production. We expect to make capital investments sufficient to at least sustain production throughout the price cycles. Free cash flow is defined as cash from operations net of capital expenditures and investments and provides funds that are available to return to shareholders, strengthen the balance sheet or reinvest back into the business for future cash flow expansion.

- **Exercise capital discipline.** Our global portfolio is deep, diverse and durable. As we consider our capital investment opportunities, we apply a rigorous framework that we believe allows for competitive free cash flow to be available to return to shareholders. We believe allocating capital based on low cost of supply resource base will result in higher returns and drive resiliency through low prices. We also balance our investments between short- and longer-cycle projects. For example, in 2025, we continued to invest in short-cycle projects in the Lower 48 segment, as well as longer-cycle projects such as Willow in Alaska. This capital allocation framework seeks to maximize free cash flow through price cycles. Cost of supply is the WTI equivalent price that generates a 10 percent after-tax return on a point-forward and fully burdened basis. Fully burdened basis includes capital infrastructure, foreign currency exchange rates, cost of carbon, price-related inflation and G&A.

- **Control our costs.** Controlling our costs, without compromising safety or environmental stewardship, is a high priority. Using various methodologies, we monitor costs monthly, on an absolute-dollar basis and a per-unit basis, and report to management. Managing costs is critical to maintaining a competitive position in our cyclical industry and positively impacts our ability to deliver strong cash from operations.

  In the second half of 2025, we announced incremental cost reductions and margin enhancements of more than $1 billion anticipated on a run-rate basis by year-end 2026. In late 2025, we initiated a restructuring, reducing our overall employee workforce, which in addition to lease operating cost improvements and opportunities in transportation and processing, is expected to contribute approximately $0.8 billion in cost reductions. We anticipate the remaining approximately $0.2 billion to be achieved through margin expansion.

- **Optimize our portfolio.** We continually evaluate our assets to determine whether they compete for capital within our portfolio and optimize as necessary, directing capital towards the most competitive investments and disposing of assets that do not compete.

  In 2025, we divested assets in Lower 48 including the Ursa and Europa fields and Ursa Oil Pipeline Company LLC, assets in the Anadarko basin and other noncore assets. *See Note 3*.

- **Add to our proved reserve base.** We primarily add to our proved reserve base in three ways:
  - Acquire interests in existing or new fields.
  - Apply new technologies and processes to improve recovery from existing fields.
  - Successfully explore, develop and exploit new and existing fields.

  Reserve replacement represents the net change in proved reserves, net of production, divided by our current year production. Our reserve replacement was 80 percent in 2025, reflecting a net decrease from dispositions in noncore assets in Lower 48 and lower prices, partially offset by development drilling activity and extensions and discoveries. Our organic reserve replacement, which excludes a net decrease of 165 MMBOE from sales and purchases, was 99 percent in 2025.

  In the three years ended December 31, 2025, our reserve replacement was 145 percent. Our organic reserve replacement during the three years ended December 31, 2025, which excludes a net increase of 905 MMBOE related to sales and purchases, was 106 percent.

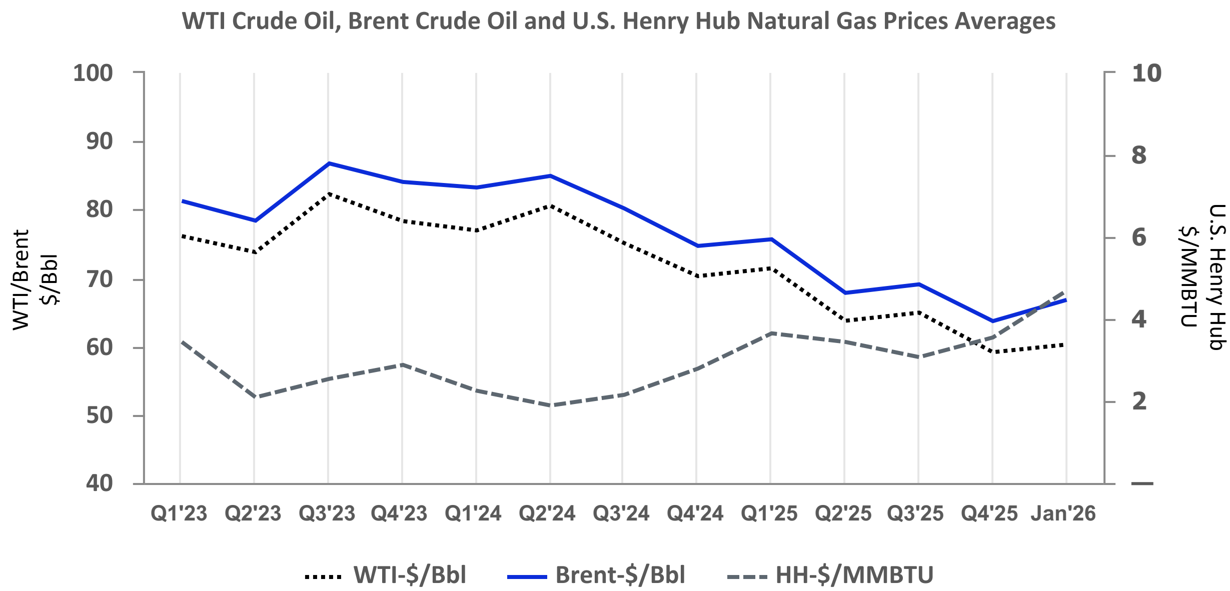
  See *"Supplementary Data - Oil and Gas Operations"* for more information.

Environmental, Social and Governance performance. We are committed to the efficient and effective exploration and production of oil and natural gas. We seek to deliver energy to the world through an integrated management system that assesses sustainability-related business risks and opportunities as part of our decision-making process, and remain committed to our targets. Recognizing the importance of ESG performance to our stakeholders and company success, we have a governance structure that extends from the board of directors to executive leadership and business unit managers.

For more information on our commitment to responsible and reliable ESG performance, *see "Contingencies—Company Response to Climate-Related Risks"* section of Management's Discussion and Analysis of Financial Condition and Results of Operation.

Commodity Prices
Commodity prices and the associated realizations are the most significant factor impacting our profitability and related returns on and of capital to our shareholders. Dynamics that could influence world energy markets and commodity prices include, but are not limited to, global economic health, supply or demand disruptions or fears thereof caused by civil unrest, global pandemics, military conflicts, actions taken by OPEC Plus and other major oil producing countries, environmental laws, tariffs, governmental policies and weather-related disruptions. Our strategy is to create value through price cycles by delivering on the financial, operational and ESG priorities that underpin our value proposition.

Our earnings and operating cash flows generally correlate with price levels for crude oil and natural gas, which are subject to factors external to the company and over which we have no control. The following graph depicts the trend in average benchmark prices for WTI crude oil, Brent crude oil and U.S. Henry Hub natural gas since 2023.



The following table presents average prices for 2025 compared to 2024:

Industry Prices		2025	2024	Change
Brent ($ per BBL)	$	**69.06**	80.76	(14)%
WTI ($ per BBL)		**64.81**	75.72	(14)%
Henry Hub ($ per MMBTU)		**3.43**	2.27	51 %
Average Realized Prices				
Bitumen realized price ($ per BBL)	$	**40.74**	47.92	(15)%
Total realized price ($ per BBL)	$	**47.01**	58.39	(19)%

Crude and bitumen prices were lower through 2025 as global oil supplies increased faster than global oil demand.

Natural gas prices increased due to stronger demand and lower inventory levels relative to 2024.

Our worldwide annual average realized price decrease was driven by lower crude and bitumen prices.

Key Operating and Financial Summary

Significant items during 2025 and recent announcements included the following:

- Reported fourth-quarter 2025 earnings per share of $1.17;
- Generated cash provided by operating activities of $19.8 billion;
- Distributed $9.0 billion to shareholders, including $5.0 billion through share repurchases and $4.0 billion through the ordinary dividend;
- Ended the year with cash, cash equivalents, restricted cash and short-term investments of $7.4 billion and long-term investments of $1.1 billion.
- Delivered full-year total company and Lower 48 production of 2,375 MBOED and 1,484 MBOED, respectively;
- Completed the integration of Marathon Oil and doubled synergy capture to more than $1 billion on a run-rate basis in 2025; achieved an additional ~$1 billion of one-time benefits;
- On track to achieve incremental cost reductions and margin enhancements of more than $1 billion on a run-rate basis by year-end 2026;
- Closed $3.2 billion in dispositions in 2025 and on track to meet $5 billion total disposition target by year-end 2026;
- Continued to advance Willow project in Alaska and equity LNG projects at NFE and NFS in Qatar and PALNG on the U.S. Gulf Coast; all projects remain on schedule with NFE startup expected in the second half of 2026;
- Achieved Lower 48 drilling and completion efficiency improvements of more than 15% year over year;
- Advanced commercial LNG strategy by placing initial 5 MTPA of PALNG Phase 1 offtake; secured additional offtake of 5 MTPA to bring total commercial offtake portfolio to 10 MTPA;
- Signed an agreement to extend the Waha Concession in Libya through 2050, with new fiscal terms, subject to normal regulatory approvals; and
- Achieved first oil at Surmont Pad 104W-A in the fourth quarter, ahead of schedule.

Outlook

Capital, Production and DD&A

Guidance for 2026 includes capital expenditures of approximately $12 billion.

Production guidance is 2.33 to 2.36 MMBOED. First-quarter 2026 production is expected to be 2.30 to 2.34 MMBOED, inclusive of weather-related downtime.

DD&A is expected to be $11.7 to $11.9 billion.

Operating Segments

We manage our operations through five operating segments, which are primarily defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; and Asia Pacific. Effective in the fourth quarter of 2025, we determined that our former Other International operating segment, which consisted of activities associated with prior operations in other countries, was no longer an operating segment. Residual results are aggregated into Corporate and Other. Our historical operating segment reporting has been recast to reflect this change.

Our combined Corporate and Other represents income and costs not directly associated with an operating segment, such as most interest income and expense; impacts from certain debt transactions; corporate overhead and certain technology activities, including licensing revenues; and unrealized holding gains or losses on equity securities. All cash and cash equivalents and short-term investments are included in Corporate and Other.

Our key performance indicators, shown in the statistical tables provided at the beginning of the operating segment sections that follow, reflect results from our operations, including commodity prices and production.

Results of Operations

This section of the Form 10-K discusses year-to-year comparisons between 2025 and 2024. For discussion of year-to-year comparisons between 2024 and 2023, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of our 2024 10-K.

Consolidated Results

Summary Operating Statistics

	2025	2024	2023
Average Net Production			
Crude oil (MBD)			
Consolidated operations	**1,133**	969	923
Equity affiliates	**12**	13	13
Total crude oil	**1,145**	982	936
Natural gas liquids (MBD)			
Consolidated operations	**411**	304	279
Equity affiliates	**8**	8	8
Total natural gas liquids	**419**	312	287
Bitumen (MBD)	**133**	122	81
Natural gas (MMCFD)			
Consolidated operations	**2,859**	2,200	1,916
Equity affiliates	**1,206**	1,233	1,219
Total natural gas	**4,065**	3,433	3,135
Total Production (MBOED)	**2,375**	1,987	1,826
Total Production (MMBOE)	**867**	727	666

	Dollars Per Unit		
Average Sales Prices			
Crude oil (per BBL)			
Consolidated operations	**$ 65.58**	76.74	78.97
Equity affiliates	**68.94**	76.76	78.45
Total crude oil	**65.62**	76.74	78.96
Natural gas liquids (per BBL)			
Consolidated operations	**20.59**	22.43	22.12
Equity affiliates	**46.20**	51.53	47.09
Total natural gas liquids	**21.07**	23.19	22.82
Bitumen (per BBL)	**40.74**	47.92	42.15
Natural gas (per MCF)			
Consolidated operations	**3.40**	2.61	3.89
Equity affiliates	**6.83**	8.22	8.46
Total natural gas	**4.44**	4.69	5.69

Worldwide Exploration Expenses	Millions of Dollars			
General and administrative; geological and geophysical, lease rental, and other	$	**226**	309	236
Leasehold impairment		**91**	6	53
Dry holes		**90**	40	109
Total Exploration Expenses	$	**407**	355	398

Total Company Production

We explore for, produce, transport and market crude oil, bitumen, natural gas, NGLs and LNG on a worldwide basis. At December 31, 2025, our operations were producing in the U.S., Norway, Canada, Australia, China, Malaysia, Qatar, Libya and Equatorial Guinea.

Total production of 2,375 MBOED increased 388 MBOED or 20 percent in 2025 compared with 2024. Production increases include:
- New wells online in the Lower 48, Canada, Australia, Norway, Alaska, Libya, China and Malaysia.
- Our acquisition of Marathon Oil in the fourth quarter of 2024.

The increase in production during 2025 was partly offset by normal field decline.

After adjusting for closed acquisitions and dispositions, production increased by 57 MBOED or 2.5 percent.

Income Statement Analysis

Unless otherwise indicated, all results in Income Statement Analysis are before-tax.

Below is select financial data provided on a consolidated basis. The full income statement can be found in *Item 8. Financial Statements and Supplementary Data*.

	Millions of Dollars		
Years Ended December 31	**2025**	2024	2023
Sales and other operating revenues	$ **58,944**	54,745	56,141
Equity in earnings of affiliates	**1,335**	1,705	1,720
Gain (loss) on dispositions	**731**	51	228
Purchased commodities	**22,325**	20,012	21,975
Production and operating expenses	**10,331**	8,751	7,693
Selling, general and administrative expenses	**893**	1,158	705
Depreciation, depletion and amortization	**11,500**	9,599	8,270
Other expenses	**20**	181	2
Income tax provision (benefit)	**4,668**	4,427	5,331

Sales and other operating revenues increased $4,199 million in 2025, primarily due to higher volumes of $6,197 million, inclusive of sales volumes from our acquisition of Marathon Oil and higher realized gas prices of $824 million and the timing of sales as compared to 2024. These increases were partially offset by lower realized crude and bitumen prices of $4,615 million and $349 million, respectively. *See Note 3*.

Equity in earnings of affiliates decreased $370 million in 2025, primarily due to lower earnings driven by lower LNG and crude prices.

Gain (loss) on dispositions increased $680 million in 2025, primarily due to gains associated with the divestitures of the Ursa and Europa fields and Ursa Oil Pipeline Company LLC and other noncore assets in our Lower 48 segment. *See Note 3*.

Purchased commodities increased $2,313 million in 2025, primarily due to higher purchased volumes associated with our acquisition of Marathon Oil, higher natural gas prices and higher purchased crude volumes, partly offset by lower crude prices. *See Note 3*

Production and operating expenses increased $1,580 million in 2025, primarily due to impacts from our acquisition of Marathon Oil in the fourth quarter of 2024 and $216 million of severance costs related to a restructuring. *See Note 3 and See Note 14*.

Selling, general and administrative expenses decreased $265 million in 2025, primarily due to the absence of transaction expenses of $545 million associated with our acquisition of Marathon Oil in 2024, partially offset by severance costs related to a restructuring in 2025. *See Note 3 and See Note 14*.

DD&A increased $1,901 million in 2025 primarily due to impacts from our acquisition of Marathon Oil in the fourth quarter of 2024 and higher production volumes. *See Note 3*.

Other expenses decreased $161 million primarily related to the absence of a loss of $173 million associated with the extinguishment of debt in the fourth quarter of 2024. *See Note 7.*

See *Note 15—Income Taxes* for information regarding our income tax provision and effective tax rate.

Segment Results

Unless otherwise indicated, discussion of Segment Results is after-tax.

A summary of the company's net income (loss) by business segment follows:

	Millions of Dollars		
Years Ended December 31	**2025**	2024	2023
Alaska	$ **730**	1,326	1,778
Lower 48	**5,264**	5,175	6,461
Canada	**741**	712	402
Europe, Middle East and North Africa	**1,224**	1,189	1,189
Asia Pacific	**1,167**	1,724	1,961
Segments Total	**9,126**	10,126	11,791
Corporate and Other	**(1,138)**	(881)	(834)
Net income (loss)	$ **7,988**	9,245	10,957

For further discussion of segment results, see the following pages.

Alaska

		2025	2024	2023
Select financial data by segment before-tax ($MM)				
Sales and other operating revenues ($MM)	$	**5,638**	6,553	7,098
Production and operating expenses ($MM)		**2,158**	1,951	1,829
Depreciation, depletion and amortization ($MM)		**1,399**	1,299	1,061
Taxes other than income taxes ($MM)		**438**	470	497
Net income (loss) ($MM)	$	**730**	1,326	1,778
Average Net Production				
Crude oil (MBD)		**177**	173	173
Natural gas liquids (MBD)		**15**	15	16
Natural gas (MMCFD)		**41**	39	38
Total Production (MBOED)		**199**	194	195
Total Production (MMBOE)		**73**	71	71
Average Sales Prices				
Crude oil ($ per BBL)	$	**71.79**	81.73	83.05
Natural gas ($ per MCF)		**3.81**	3.90	4.47

The Alaska segment primarily explores for, produces, transports and markets crude oil, NGLs and natural gas. In 2025, Alaska contributed 12 percent of our consolidated liquids production and one percent of our consolidated natural gas production.

Net Income (Loss)

Alaska reported earnings of $730 million in 2025, compared with earnings of $1,326 million in 2024.

Decreases to earnings included lower revenues resulting from lower commodity prices of $509 million, partly offset by higher produced volumes of $78 million. Additional decreases to earnings included higher production and operating expenses of $151 million, driven by higher lease operating expenses and well work activity and severance costs related to a restructuring, and higher DD&A of $73 million, primarily driven by higher rates. *See Note 14*.

Production

Average production increased five MBOED in 2025 compared with 2024, primarily due to new wells online and less downtime.

The production increase was partly offset by normal field decline.

Lower 48

		2025	2024	2023
Select financial data by segment before-tax ($MM)				
Sales and other operating revenues ($MM)	**$**	**41,395**	37,026	38,237
Production and operating expenses ($MM)		**5,856**	4,751	4,199
Depreciation, depletion and amortization ($MM)		**8,121**	6,442	5,722
Taxes other than income taxes ($MM)		**1,506**	1,378	1,352
Net income (loss) ($MM)	**$**	**5,264**	5,175	6,461
Average Net Production				
Crude oil (MBD)		**749**	602	569
Natural gas liquids (MBD)		**382**	279	256
Natural gas (MMCFD)		**2,119**	1,625	1,457
Total Production (MBOED)		**1,484**	1,152	1,067
Total Production (MMBOE)		**542**	422	389
Average Sales Prices				
Crude oil ($ per BBL)	**$**	**63.18**	74.17	76.19
Natural gas liquids ($ per BBL)		**20.64**	22.02	21.73
Natural gas ($ per MCF)		**1.74**	0.87	2.12

The Lower 48 segment consists of operations located in the contiguous U.S. and related commercial operations. During 2025, the Lower 48 contributed 67 percent of our consolidated liquids production and 74 percent of our consolidated natural gas production.

Net Income (Loss)

Lower 48 reported earnings of $5,264 million in 2025, compared with earnings of $5,175 million in 2024.

Increases to earnings included higher revenues resulting from higher volumes of $3,890 million, inclusive of volumes from our acquisition of Marathon Oil, partly offset by lower commodity prices of $1,999 million, driven by lower crude prices. Additional increases included higher gains on dispositions of $494 million, primarily associated with the divestitures of the Ursa and Europa fields and Ursa Oil Pipeline Company LLC, and other noncore assets.

Decreases to earnings included higher DD&A of $1,330 million and higher production and operating expenses of $875 million, primarily driven by impacts from our acquisition of Marathon Oil. *See Note 3.*

Production

Total average production increased 332 MBOED in 2025 compared with 2024, primarily due to new wells online from our development programs in the Delaware Basin, Eagle Ford, Bakken and Midland Basin and the impact from our acquisition of Marathon Oil. *See Note 3.*

Production increases were partly offset by normal field decline.

Dispositions

In 2025, we completed multiple divestitures, including the Ursa and Europa fields and Ursa Oil Pipeline Company LLC for net proceeds of $699 million, the Anadarko Basin for net proceeds of $1.2 billion and other noncore assets for $1.1 billion. Production from these assets averaged approximately 33 MBOED in 2024. *See Note 3.*

Canada

		2025	2024	2023
Select financial data by segment before-tax ($MM)				
Sales and other operating revenues ($MM)	$	**3,625**	3,514	3,006
Production and operating expenses ($MM)		**833**	902	619
Depreciation, depletion and amortization ($MM)		**556**	639	420
Taxes other than income taxes ($MM)		**27**	31	26
Net Income (Loss) ($MM)	$	**741**	712	402
Average Net Production				
Crude oil (MBD)		**17**	17	9
Natural gas liquids (MBD)		**6**	6	3
Bitumen (MBD)		**133**	122	81
Natural gas (MMCFD)		**125**	115	65
Total Production (MBOED)		**177**	164	104
Total Production (MMBOE)		**65**	60	38
Average Sales Prices				
Crude oil ($ per BBL)	$	**55.35**	64.47	66.19
Natural gas liquids ($ per BBL)		**22.54**	29.59	26.13
Bitumen ($ per BBL)		**40.74**	47.92	42.15
Natural gas ($ per MCF)*		**1.02**	0.54	1.80

**Average sales prices include unutilized transportation costs.*

The Canada segment operations include the Surmont oil sands development in Alberta, the Montney unconventional play in British Columbia and commercial operations. In 2025, Canada contributed nine percent of our consolidated liquids production and five percent of our consolidated natural gas production.

Net Income (Loss)

Canada reported earnings of $741 million in 2025 compared with earnings of $712 million in 2024.

Increases to earnings included higher revenues resulting from higher volumes of $142 million and the timing of sales as compared with 2024 partly offset by lower commodity prices of $303 million. Increases to earnings included lower DD&A of $63 million driven by year-end 2024 upward reserve revisions and higher other income of $62 million primarily from a change in fair value measurement associated with the Surmont contingent consideration arrangement. Additional increases to earnings included lower production and operating expenses of $52 million driven by the absence of prior-year planned turnaround activity at Surmont. *See Note 11.*

Production

Total average production increased 13 MBOED in 2025 compared with 2024. Increases to production resulted from new wells online in the Montney and Surmont and the absence of prior-year planned turnaround activity at Surmont.

Production increases were partly offset by normal field decline.

Europe, Middle East and North Africa

		2025	2024	2023
Select financial data by segment before-tax ($MM)				
Sales and other operating revenues ($MM)	$	**6,484**	5,788	5,854
Production and operating expenses ($MM)		**962**	671	593
Depreciation, depletion and amortization ($MM)		**912**	761	587
Taxes other than income taxes ($MM)		**46**	41	39
Net income (loss) ($MM)	$	**1,224**	1,189	1,189
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**131**	118	112
Natural gas liquids (MBD)		**8**	4	4
Natural gas (MMCFD)		**511**	371	308
Total Production (MBOED)		**224**	184	168
Total Production (MMBOE)		**82**	67	61
Average Sales Prices				
Crude oil ($ per BBL)	$	**68.95**	80.92	83.96
Natural gas liquids ($ per BBL)		**16.53**	40.29	41.13
Natural gas ($ per MCF)		**10.87**	10.70	12.68

The Europe, Middle East and North Africa segment consists of operations principally located in the Norwegian sector of the North Sea, the Norwegian Sea, Qatar, Libya, Equatorial Guinea and commercial and terminalling operations in the U.K. In 2025, our Europe, Middle East and North Africa operations contributed eight percent of our consolidated liquids production and 18 percent of our consolidated natural gas production.

Net Income (Loss)

The Europe, Middle East and North Africa segment reported earnings of $1,224 million in 2025 compared with earnings of $1,189 million in 2024.

Earnings in 2025 included higher revenues resulting from higher volumes of $296 million, including volumes from our Equatorial Guinea assets from the acquisition of Marathon Oil, partly offset by lower overall realized commodity prices of $185 million, driven by lower crude prices. *See Note 3.*

Decreases to earnings included higher production and operating expenses of $88 million, primarily from our acquisition of Marathon Oil. *See Note 3.*

Consolidated Production

Average consolidated production increased 40 MBOED in 2025, compared with 2024. The consolidated production increase was primarily due to the impact from assets acquired from Marathon Oil as well as new wells online in Norway and Libya. *See Note 3.*

The production increase was partly offset by normal field decline.

Asia Pacific

		2025	2024	2023
Select financial data by segment before-tax ($MM)				
Sales and other operating revenues ($MM)	$	**1,770**	1,847	1,913
Production and operating expenses ($MM)		**367**	384	391
Depreciation, depletion and amortization ($MM)		**460**	425	455
Taxes other than income taxes ($MM)		**57**	109	117
Net income (loss) ($MM)	$	**1,167**	1,724	1,961
Consolidated Operations				
Average Net Production				
Crude oil (MBD)		**59**	59	60
Natural gas (MMCFD)		**63**	50	48
Total Production (MBOED)		**70**	67	68
Total Production (MMBOE)		**26**	25	25
Average Sales Prices				
Crude oil ($ per BBL)	$	**71.05**	82.42	84.79
Natural gas ($ per MCF)		**3.59**	3.74	3.95

The Asia Pacific segment consists of operations in China, Malaysia, and Australia, and commercial operations in China, Singapore and Japan. During 2025, Asia Pacific contributed four percent of our consolidated liquids production and two percent of our consolidated natural gas production.

Net Income (Loss)

Asia Pacific reported earnings of $1,167 million in 2025, compared with $1,724 million in 2024.

Decreases to earnings included lower revenues resulting from lower commodity prices of $206 million. Additional decreases to earnings included lower earnings from equity affiliates of $271 million, primarily due to lower LNG sales prices and higher exploration expenses of $64 million, primarily driven by dry hole expenses associated with certain wells in Malaysia and Australia.

Consolidated Production

Average consolidated production increased three MBOED in 2025, compared with 2024. Increases to production were primarily due to development activity in Bohai Bay in China and Gumusut in Malaysia.

Production increases were partly offset by normal field decline.

Corporate and Other

		Millions of Dollars		
		2025	2024	2023
Net income (loss)				
Net interest expense	**$**	**(494)**	(379)	(360)
Corporate G&A expenses		**(486)**	(716)	(357)
Technology		**(144)**	(137)	(34)
Other income (expense)		**(14)**	352	(70)
	$	**(1,138)**	(880)	(821)

Net interest expense consists of interest and debt expense, net of interest income and capitalized interest. Net interest expense increased in 2025 due to higher interest expense driven by debt assumed from our acquisition of Marathon Oil. *See Note 3 and Note 7.*

Corporate G&A expenses include compensation programs and staff costs. These expenses decreased by $230 million in 2025 compared with 2024, primarily due to the absence of transaction expenses of $432 million associated with our acquisition of Marathon Oil in 2024, partially offset by severance costs related to a restructuring in 2025. *See Note 3 and Note 14*.

Technology includes our investments in low-carbon technology opportunities as well as other new technologies or businesses and licensing revenues. Other new technologies or businesses and LNG licensing activities are focused on both conventional and tight oil reservoirs, shale gas, oil sands, enhanced oil recovery as well as LNG.

Other income (expense) or "Other" includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, other costs not directly associated with an operating segment, gains or losses on early retirement of debt, holding gains or losses on equity securities and pension settlement expense. Earnings in “Other” decreased by $366 million in 2025 compared with 2024. This was primarily due to the absence of a tax benefit of $455 million as a result of the acquisition of Marathon Oil in 2024 and the subsequent utilization of foreign tax credits. The earnings decrease was partly offset by an increase due to the absence of a loss of $147 million associated with the extinguishment of debt in the fourth quarter of 2024. *See Note 3, Note 7 and Note 15*.

Capital Resources and Liquidity
Financial Indicators

	Millions of Dollars Except as Indicated		
	2025	2024	2023
Net cash provided by operating activities	$ **19,796**	20,124	19,965
Cash and cash equivalents	**6,497**	5,607	5,635
Short-term investments	**484**	507	971
Short-term debt	**1,020**	1,035	1,074
Total debt	**23,444**	24,324	18,937
Total equity	**64,487**	64,796	49,279
Percent of total debt to capital*	**27 %**	27	28
Percent of floating-rate debt to total debt	**1 %**	1	2

Balance Sheet related line items are shown as of December 31st.
**Capital includes total debt and total equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, including cash generated from operating activities, our commercial paper and credit facility programs and our ability to sell securities using our shelf registration statement. In 2025, the primary uses of our available cash were $12.6 billion to support our ongoing capital expenditures and investments program; $5.0 billion to repurchase common stock; $4.0 billion to pay the ordinary dividend; and $0.9 billion to retire debt, partly offset by proceeds from asset sales of $3.2 billion. In 2025, cash and cash equivalents increased by $0.9 billion to $6.5 billion. *See Note 3 and Note 7.*

At December 31, 2025, we had cash and cash equivalents of $6.5 billion, short-term investments of $0.5 billion, and available borrowing capacity under our credit facility of $5.5 billion, totaling approximately $12.5 billion of liquidity. In addition, we have long-term investments in debt securities of $1.1 billion. We believe current cash balances and cash generated by operations, together with access to external sources of funds as described below in the “Significant Changes in Capital” section, will be sufficient to meet our funding requirements in the near- and long-term, including our capital spending program, capital return program and required debt payments.

Significant Changes in Capital

Operating Activities

Cash provided by operating activities in 2025 totaled $19.8 billion, compared with $20.1 billion for 2024, and $20.0 billion for 2023. The decrease in 2025 compared to 2024 resulted from lower commodity prices, mostly offset by operations from the 2024 Marathon Oil acquisition. *See Note 3.*

The increase in cash provided by operating activities in 2024 compared to 2023 is due to increased production primarily from Canada and the Lower 48, including the Surmont 50 percent working interest acquired in the fourth quarter of 2023 and our acquisition of Marathon Oil in late 2024. The increase in production was partly offset by lower commodity prices and lower distributions from equity affiliates. *See Note 3.*

Our short- and long-term operating cash flows are highly dependent on the prices for crude oil, bitumen, natural gas, LNG and NGLs. Prices and margins in our industry have historically been volatile, driven by market conditions beyond our control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of absolute production volumes, as well as the product and location mix, is another significant factor impacting our cash flows. Full-year production averaged 2,375 MBOED in 2025, an increase of 388 MBOED or 20 percent compared to 2024. First-quarter 2026 production is expected to be 2.30 MMBOED to 2.34 MMBOED. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact investment decisions; the effects of price changes on production sharing and variable-royalty contracts; acquisition and disposition of fields; field production decline rates; new technologies; operating efficiencies; timing of startups and major turnarounds; political instability; weather-related disruptions; and the addition of proved reserves through exploratory success and their timely and cost-effective development. While we actively monitor and manage these factors, changes in production levels can cause variability in cash flows, although we generally experience less variability in our cash flows due to changes in production levels than due to changes in commodity prices.

Investing Activities

In 2025, we invested $12.6 billion in capital expenditures and investments, $0.5 billion of which was primarily payments towards our equity investments in LNG projects, including NFE4, NFS3 and PALNG, while the remainder funded our operating capital program. Capital expenditures invested in 2024 and 2023 were $12.1 billion and $11.2 billion, respectively. *See the "Capital Expenditures and Investments" section.*

In August 2025, we announced a total disposition target of $5 billion by year-end 2026. We disposed of $3.2 billion of assets in 2025 and we expect to meet our $5 billion disposition target by year-end 2026. *See Note 3.*

Proceeds from asset sales were $3.2 billion in 2025 compared with $0.3 billion in 2024 and $0.6 billion in 2023. In 2025, we sold Lower 48 assets in the Anadarko basin for net proceeds of $1.2 billion and our interest in the Ursa and Europa fields, and Ursa Oil Pipeline Company LLC for net proceeds of $0.7 billion. Additionally, we sold other noncore Lower 48 and Corporate assets for approximately $1.3 billion*. See Note 3.*

In the fourth quarter of 2024, after exercising our preferential rights, we completed an acquisition that increased our working interest by approximately five percent in the Kuparuk River Unit and approximately 0.4 percent in the Prudhoe Bay Unit in Alaska from Chevron U.S.A. Inc. and Union Oil Company of California for $296 million, before customary adjustments. *See Note 3.*

In October 2023, we acquired the remaining 50 percent working interest in Surmont from TotalEnergies EP Canada Ltd. for approximately $2.7 billion of cash after customary adjustments. We funded this transaction by issuing new long-term debt. *See Note 3 and Note 7.*

We invest in short-term and long-term investments as part of our cash investment strategy, the primary objective of which is to protect principal, maintain liquidity and provide yield and total returns; these investments include time deposits, commercial paper, as well as debt securities classified as available for sale. Funds needed for short-term investments to support our operating plan and provide resiliency to react to short-term price volatility are invested in highly liquid instruments with maturities of less than one year. Funds we consider available to maintain resiliency in longer term price downturns and to capture opportunities outside a given operating plan are invested in highly liquid instruments with maturities of greater than one year. *See Note 10 and Note 17.*

Investing activities in 2025 included net purchases of $55 million of investments. We had net sales of $502 million of short-term investments and net purchases of $557 million of long-term investments. *See Note 17.*

Financing Activities

Our debt balance at December 31, 2025 was $23.4 billion compared with $24.3 billion at December 31, 2024. The current portion of debt, including payments for finance leases, is $1.0 billion.

In 2025, the company retired $0.7 billion principal amount of debt at maturity, consisting of $0.2 billion of our 3.35% Notes, $0.4 billion of our 2.4% Notes and $0.1 billion of our 8.2% Debentures.

In November 2024, we acquired Marathon Oil. At closing, the acquisition was valued at $16.5 billion and was allocated to assets acquired and liabilities assumed. ConocoPhillips common stock was issued and exchanged for outstanding Marathon Oil shares. With the acquisition, we also assumed Marathon Oil's debt of approximately $4.6 billion. *See Note 3 and Note 7.*

In 2024, the company retired $726 million principal amount of Notes at maturity consisting of $265 million of our 3.35% Notes and $461 million of our 2.125% Notes. In addition, we completed concurrent debt transactions consisting of new long-term debt issuances of $5.2 billion; a $4.1 billion repurchase of certain existing Marathon Oil and ConocoPhillips debt (with priority for Marathon Oil debt assumed); a non-cash obligor exchange offer to retire $0.9 billion of Marathon Oil debt in exchange for new ConocoPhillips debt; and remarketing of $0.4 billion in available municipal bonds. The debt transactions simplified our capital structure, extended the debt portfolio's weighted average maturity, lowered its weighted average coupon and reduced near-term maturities. *See Note 7.*

In 2023, we issued $2.7 billion principal amount of new debt to fund our acquisition of the remaining 50 percent working interest in Surmont and completed refinancing transactions consisting of $1.1 billion in tender offers to repurchase existing debt with cash and a $1.1 billion new debt issuance to fund the repurchases, extending the weighted average maturity of our portfolio from 15 to 17 years and reducing near-term debt maturities. *See Note 7.*

In February 2025, we refinanced our revolving credit facility maintaining a total aggregate principal amount of $5.5 billion and extended the expiration to February 2030. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper program. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or any of its consolidated subsidiaries. The amount of the facility is not subject to redetermination prior to its expiration date.

Credit facility borrowings may bear interest at a margin above the Secured Overnight Financing Rate (SOFR). The agreement calls for commitment fees on available, but unused, amounts. The agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

The revolving credit facility supports ConocoPhillips Company’s ability to issue up to $5.5 billion of commercial paper, which is primarily a funding source for short-term working capital needs. Commercial paper maturities are generally limited to 90 days. With no commercial paper outstanding and no direct borrowings or letters of credit, we had access to $5.5 billion in available borrowing capacity under our revolving credit facility at December 31, 2025.

In November 2025, Fitch affirmed our long-term credit rating. The current credit ratings on our long-term debt are:

- Fitch: “A” with a “stable” outlook
- S&P: “A-” with a “stable” outlook
- Moody's: “A2” with a “stable” outlook

See Note 7 for additional information on debt and the revolving credit facility.

We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, upon downgrade of our credit ratings. If our credit ratings are downgraded from their current levels, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

Certain of our project-related contracts, commercial contracts and derivative instruments contain provisions requiring us to post collateral. Many of these contracts and instruments permit us to post either cash or letters of credit as collateral. At December 31, 2025 and 2024, we had direct bank letters of credit of $331 million and $278 million, respectively, which secured performance obligations related to various purchase commitments incident to the ordinary conduct of business. In the event of a credit rating downgrade, we may be required to post additional letters of credit.

Shelf Registration

We have a universal shelf registration statement on file with the SEC under which we have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

Capital Requirements

For information about our capital expenditures and investments, see the "Capital Expenditures and Investments" section. For information about our debt balances and related debt financing transactions, see the "Significant Changes in Capital - Financing Activities" section.

We believe in delivering value to our shareholders through our return of capital framework. The framework is structured to deliver a compelling, growing ordinary dividend and through-cycle share repurchases. We anticipate returning greater than 30 percent of cash from operating activities through cycles. Our 2025 total capital returned was $9.0 billion.

Consistent with our commitment to deliver value to shareholders, for the full year of 2025, we paid ordinary dividends of $3.18 per common share. In 2024 we paid ordinary dividends of $2.52 and VROC payments of $0.60 per common share and in 2023 we paid ordinary dividends of $2.11 and VROC payments of $2.50 per common share. In February 2026, we declared a first-quarter ordinary dividend of $0.84 per common share payable March 2, 2026, to shareholders of record on February 18, 2026.

Our Board may determine not to pay a dividend in a quarter or may cease declaring a dividend at any time.

In late 2016, we initiated our current share repurchase program. In October 2024, our Board of Directors approved an increase from our prior authorization of $45 billion by a total of the lesser of $20 billion or the number of shares issued in our acquisition of Marathon Oil, such that the company is not to exceed $65 billion in aggregate repurchases. Share repurchases were $5.0 billion, $5.5 billion, and $5.4 billion in 2025, 2024, and 2023, respectively. As of December 31, 2025, share repurchases since the inception of our current program totaled 486.1 million shares for $39.3 billion since 2016. Repurchases are made at management's discretion, at prevailing prices, subject to market conditions and other factors.

For more information on factors considered when determining the levels of returns of capital *see "Item 1A—Risk Factors – Our ability to execute our capital return program is subject to certain considerations."*

As of December 31, 2025, in addition to the priorities described above, we have contractual obligations to purchase goods and services of approximately $45.0 billion. We expect to fulfill $5.0 billion of these obligations in 2026 with the remainder over the next 25 years. A substantial amount of LNG offtake and other product purchases are expected to be offset in the same or approximately same periods by cash received from the related sales transactions. These figures exclude purchase commitments for jointly owned fields and facilities where we are not the operator.

The following table summarizes our aggregate future contractual purchase obligations as of December 31, 2025:

	Millions of Dollars
	2025
LNG offtake, regasification and related vessels	**$ 29,722**
Other capacity obligations	**10,890**
Other product purchases	**3,094**
Other obligations	**1,271**
Total	**$ 44,977**

Capital Expenditures and Investments

	Millions of Dollars		
	2025	2024	2023
Alaska	$ **3,607**	3,194	1,705
Lower 48	**6,702**	6,510	6,487
Canada	**593**	551	456
Europe, Middle East and North Africa	**1,194**	1,021	1,111
Asia Pacific	**342**	370	354
Segments Total	**12,438**	11,646	10,113
Corporate and Other	**115**	472	1,135
Capital Program*	$ **12,553**	$ **12,118**	$ **11,248**

** Excludes capital related to acquisitions of businesses, net of cash acquired.*

Our capital expenditures and investments for the three-year period ended December 31, 2025, totaled $35.9 billion. The 2025 capital expenditures and investments supported key operating activities and acquisitions, primarily:

- Appraisal and development activities in Alaska related to the Western North Slope, inclusive of Willow, and development activities in the Greater Kuparuk Area.
- Development activities in the Lower 48, primarily in the Delaware Basin, Eagle Ford, Midland Basin and Bakken.
- Appraisal and development activities in the Montney as well as development and optimization of Surmont in Canada.
- Development and appraisal activities across assets in Norway and development activities in Libya.
- Continued development activities in China.
- Investments in NFE4, NFS3 and PALNG.

2026 Capital Budget

In February 2026, we announced our 2026 operating plan capital is expected to be approximately $12 billion. The plan includes funding for ongoing development drilling programs, major projects, exploration and appraisal activities and base maintenance.

Guarantor Summarized Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC with respect to publicly held debt securities. ConocoPhillips Company is 100 percent owned by ConocoPhillips. Burlington Resources LLC is 100 percent owned by ConocoPhillips Company. ConocoPhillips and/or ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of Burlington Resources LLC with respect to its publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several.

The following tables present summarized financial information for the Obligor Group, as defined below:

- The Obligor Group will reflect guarantors and issuers of guaranteed securities consisting of ConocoPhillips, ConocoPhillips Company and Burlington Resources LLC.
- Consolidating adjustments for elimination of investments in and transactions between the collective guarantors and issuers of guaranteed securities are reflected in the balances of the summarized financial information.
- Non-Obligated Subsidiaries are excluded from this presentation.

Transactions and balances reflecting activity between the Obligors and Non-Obligated Subsidiaries are presented separately below:

Summarized Income Statement Data

	Millions of Dollars
	2025
Revenues and Other Income	**$ 38,564**
Income (loss) before income taxes*	**7,316**
Net income (loss)	**7,988**

**Includes approximately $11.6 billion of purchased commodities expense for transactions with Non-Obligated Subsidiaries.*

Summarized Balance Sheet Data

	Millions of Dollars
	December 31, 2025
Current assets	**$ 8,206**
Amounts due from Non-Obligated Subsidiaries, current	***855***
Noncurrent assets	**130,320**
Amounts due from Non-Obligated Subsidiaries, noncurrent	***11,231***
Current liabilities	**4,947**
Amounts due to Non-Obligated Subsidiaries, current	***1,244***
Noncurrent liabilities	**74,824**
Amounts due to Non-Obligated Subsidiaries, noncurrent	***52,813***

Contingencies

We are subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated. See “Critical Accounting Estimates” and *Note 9* for information on contingencies.

Legal and Tax Matters

We are subject to various lawsuits and claims, including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, climate change, personal injury and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties, claims of alleged environmental contamination and damages from historic operations and climate change. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required. *See Note 15*.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions;
- U.S. Federal Clean Water Act, which governs discharges to water bodies;
- EU Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals;
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage, and disposal of solid waste;
- U.S. Federal Oil Pollution Act of 1990, under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the U.S.;
- U.S. Federal Emergency Planning and Community Right-to-Know Act, which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments;
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells;
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages; and
- EU Trading Directive resulting in EU Emissions Trading Scheme (EU ETS).

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also establish standards and impose obligations for the remediation of releases of hazardous substances and hazardous wastes. In most cases, these regulations require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards and water quality standards, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the U.S. and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the U.S. and Canada.

An example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas otherwise trapped in lower permeability rock formations. A range of local, state, federal, or national laws and regulations currently govern hydraulic fracturing operations, with hydraulic fracturing currently prohibited in some jurisdictions. Although hydraulic fracturing has been conducted for many decades, potential new laws, regulations and permitting requirements from various state environmental agencies, and others could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards that are designed to meet government requirements. Our practices continually evolve as technology improves and regulations change.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their equivalents in their respective jurisdictions. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We occasionally receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain waste attributable to our past operations. As of December 31, 2025, there were 20 sites around the U.S. in which we were identified as a potentially responsible party under CERCLA and comparable state laws.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Expensed environmental costs were $834 million in 2025 and are expected to be approximately $1.0 billion in each of 2026 and 2027. Capitalized environmental costs were $669 million in 2025 and are expected to be about $750 million and $550 million in 2026 and 2027, respectively.

Accrued liabilities for remediation activities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA, and similar state or international laws that require us to undertake certain investigative and remedial activities at sites where we conduct or once conducted operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation but which are not currently the subject of CERCLA, RCRA, or other agency enforcement activities. The laws that require or address environmental remediation may apply retroactively and regardless of fault, the legality of the original activities or the current ownership or control of sites. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2025, our balance sheet included total accrued environmental costs of $220 million, compared with $206 million at December 31, 2024, for remediation activities in the U.S. and Canada. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent concerns in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

See Item 1A. Risk Factors—We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations and Note 9 for information on environmental litigation.

Climate Change
Continuing political and social attention to the issue of global climate change has resulted in a broad range of proposed or promulgated state, national and international laws focusing on GHG emissions reduction. These laws apply or could apply in countries where we have interests or may have interests in the future. Additionally, some laws have been rescinded or delayed, creating policy swings that result in compliance uncertainty. Laws in this field continue to evolve and while it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our operational results and financial condition. Examples of legislation and precursors for possible regulation that do or could affect our operations include:

Emissions trading schemes.
- EU ETS is the program through which many of the EU member states aim to reduce emissions. Our cost of compliance with the EU ETS in 2025 was approximately $21 million (net share before-tax).
- The U.K. Emissions Trading Scheme (U.K. ETS) is the program with which the U.K. has replaced the EU ETS. Our cost of compliance with the U.K. ETS in 2025 was approximately $2.2 million (net share before-tax).

GHG regulations for emissions reductions.
- The Alberta Technology Innovation and Emissions Reduction (TIER) regulation requires any existing facility with emissions equal to or greater than 100,000 metric tonnes of carbon dioxide, or equivalent, per year to meet a facility benchmark intensity. There was no cost of compliance related to this regulation in 2025, as our Surmont asset outperformed its target benchmark intensity over the full year reporting period.
- As of April 2024, the British Columbia Output Based Pricing System (BC OBPS) regulation requires facilities or linear operations (such as oil and gas gathering systems) with emissions equal to or greater than 10,000 metric tonnes of carbon dioxide or equivalent per year to remit payments on the difference between actual emissions and allowable emissions based on product and activity benchmarks. The benchmarks and guidance for these emissions have yet to be finalized, and compliance payments for 2025 are not due until later in 2026. Based on interim benchmarks, our BC OBPS obligation is expected to total a maximum of $12.3 million (net share before-tax) for Montney in 2025.
- In 2024, the EU passed regulation on the reduction of methane emissions in the energy sector that will apply a methane limit on oil and gas imports to the EU, as well as mandate the monitoring, reporting, verification and reduction of methane emissions.
- Our APLNG assets in Australia are subject to the Safeguard Mechanism, enacted through the National Greenhouse and Energy Reporting Act 2007. In the previous Australian financial year of July 1, 2024, to June 30, 2025, our operated downstream APLNG facility was in excess of its baseline emissions, while the upstream partner-operated facilities were below their baseline emissions. As there was a surplus of eligible carbon units across the joint venture, there was no expense incurred by ConocoPhillips for the 2025 Australian financial year.
- In 2024 the U.S. EPA published final rulemaking for New Source Performance Standards (OOOOb) and Emissions Guidelines (OOOOc). Implementing this regulation across our U.S. portfolio will result in additional compliance costs.

Carbon taxes in certain jurisdictions.
- Effective April 1, 2025, the Canadian federal government set the consumer carbon price to zero and no longer requires a consumer carbon tax going forward. This is separate from the obligated industrial carbon pricing schemes of Alberta TIER and BC OBPS, which remain in place. Our operations outside of industrial carbon pricing schemes were minimal at Surmont for the first quarter of 2025, and no Federal Fuel charges were incurred at Montney in 2025.
- Our cost of compliance with Norwegian carbon legislation in 2025 was approximately $42 million (net share before-tax).

Other environmental regulations.
- The White House Council on Environmental Quality (CEQ) issued final National Environmental Policy Act implementation regulations (NEPA Phase 2) in 2024. Since then, the DC Circuit Court has suggested that CEQ lacks authority to adopt any binding regulations, introducing potential uncertainty into the regulatory process.
- Climate Superfund laws. In 2024, New York and Vermont passed legislation seeking to hold certain energy companies financially responsible for state climate change mitigation and adaptation measures, following the "polluter pays" model of existing Superfund laws. This responsibility may include paying into a fund for infrastructure repairs and recovery from extreme weather events that would otherwise be covered by the government. While only two U.S. states have enacted such laws to date, it is likely that more states will consider a similar approach. Compliance with such legislation may expose us to significant additional liabilities.

- Climate Private Action laws. In 2025, California, New Hampshire, and Oregon introduced bills seeking to create a private right of action for individuals to bring strict liability claims for alleged damages related to climate change impacts (including non-economic, actual and punitive damages). These bills also authorize insurance companies to pursue subrogation claims to recover damages for amounts paid to insureds for climate change impacts.

Non-regulatory initiatives or agreements.

- The Global Methane Pledge (GMP) was launched at COP26 by the EU and the U.S., a global initiative to reduce global methane emissions by at least 30 percent from 2020 levels by 2030.
- The agreement reached in Paris in December 2015 at the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change set out a process for achieving global emissions reductions. Accordingly, parties to the Paris Agreement have set targets to reduce emissions by 2030. While the current administration has officially withdrawn the U.S. from the Paris Agreement, some U.S. states have indicated that they plan to remain committed to the goals of the agreement.

Regulated sustainability disclosures.
Governments and financial regulators are developing new reporting rules requiring increased disclosure around a range of sustainability topics. The patchwork of reporting standards that is developing may require significant increases in disclosures, which may be costly to implement. In June 2023 the International Sustainability Standards Board issued inaugural sustainability reporting standards; in October 2023 in California multiple bills were signed into law requiring climate-related disclosures for companies that conduct business in the state; in September 2024, the Australian Government passed legislation which mandated a new standard for climate-related disclosures; and in the EU, the Corporate Sustainability Reporting Directive is expected to be finalized in 2026.

Compliance with changes in laws and regulations that create a GHG tax, emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation or regulation is enacted;
- The timing of the introduction of such legislation or regulation;
- The nature of the legislation (such as a cap and trade system or a tax on emissions) or regulation;
- The price placed on GHG emissions (either by the market or through a tax);
- The GHG emissions reductions required;
- The price and availability of offsets;
- The amount and allocation of allowances;
- Technological and scientific developments leading to new products or services;
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature); and
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

See Item 1A. Risk Factors—Existing and future laws, regulations and internal initiatives relating to global climate changes, such as limitations on GHG emissions may impact or limit our business plans, result in significant expenditures, promote alternative uses of energy or reduce demand for our products and Note 9 for information on climate change litigation.

Company Response to Climate-Related Risks
The objective of our Climate-related Risk Strategy is to manage climate-related risk, optimize opportunities and equip the company to respond to changes in key uncertainties, including government policies around the world, emissions reduction technologies, alternative energy technologies and changes in consumer trends. The strategy guides our choices around portfolio composition, emissions reductions, targets, incentives, emissions-related technology development, and our climate-related policy and finance sector engagement.

Our Climate-related Risk Strategy is intended to enable us to responsibly meet the global demand for energy, deliver competitive returns on and of capital and work to meet our operational emissions-reduction targets. First, meeting global energy demand requires a focus on delivering production that will best compete in any energy demand scenario. This production will be delivered from resources with a competitive cost of supply and low operational GHG intensity, as well as portfolio diversity by market and asset type. Next, our focus is on delivering superior returns through the cycles based on our foundational principles of balance sheet strength, peer-leading distributions and disciplined investments. Finally, to drive accountability for the emissions that are within our ownership, we are progressing toward our Scope 1 and Scope 2 emissions intensity targets.

Key elements of the Climate-related Risk Strategy include:

- Strategic flexibility and portfolio composition
  - Building a resilient asset portfolio with a focus on low cost of supply and low operational GHG intensity to meet global energy demand.
  - Committing to capital discipline through use of a fully burdened cost of supply, including cost of carbon, as the basis for capital allocation.
  - Testing our portfolio against future energy demand scenarios through a comprehensive scenario planning process that helps us assess the resilience of our corporate strategy to climate risk.
- Scope 1 and 2 GHG emissions targets and reductions
  - Setting targets for emissions over which we have ownership and control.
  - Reducing emissions through the marginal abatement cost curve process.
- LNG and technology
  - Building an attractive LNG portfolio as an important component of responsibly meeting global energy demand due to LNG's opportunity to displace higher-emissions fuels such as coal for electricity generation.
  - Evaluating potential investments in emerging alternative energy sources and low-carbon technologies.
- External engagement
  - Supporting a well-designed, economy-wide price on carbon and development of other policy and legislation to address end-use emissions.
  - Working with our suppliers and commercial partners to understand our emissions along the value chain.

Our Climate-related Risk Strategy does not include a Scope 3 emissions target. We recognize that end-use emissions must be reduced to meet global climate objectives. However, it is our view that supply-side constraints through Scope 3 targets for North American and European upstream oil and gas producers would be counterproductive to climate goals. In the absence of policy measures that address global demand, Scope 3 targets would shift production to other global operators, potentially eroding energy security and increasing emissions. This is why we have consistently supported a well-designed, economy wide price on carbon as well as the development of other policies or legislation that could address end-use emissions. We have also supported policy interests beyond carbon pricing to include energy efficiency, end-use emissions policy and regulatory action, such as support for the direct federal regulation of methane.

In support of addressing our Scope 1 and 2 emissions, we have made recent progress in several key areas.

- Completed our 2025 scope 1 and 2 emissions reduction projects within the allotted capital and cost budget. These projects will support our GHG emissions intensity reduction target of 50-60 percent by 2030 from a 2016 baseline for both gross operated and net equity emissions.
- Achieved the Gold Standard Reporting for emissions reporting in the Oil and Gas Methane Partnership 2.0 Initiative for the second consecutive year.
- Achieved our target of zero routine flaring by the end of 2025 for heritage ConocoPhillips assets by taking all economically viable steps to eliminate routine flaring in accordance with the World Bank Zero Routine Flaring Initiative.
- Introduced a new commitment to maintain flaring intensity of less than 0.75 percent of gas produced at operated assets, to be implemented in 2026.

See Item 1A. Risk Factors—Our ability to successfully execute on our plans to reduce our operational GHG emissions intensity is subject to a number of risks and uncertainties, and such reductions may be costly and challenging to achieve.

New Accounting Standards

For discussion of new accounting standards, *see Note 23.*

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. *See Note 1* for descriptions of our significant accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent there is a reasonable likelihood materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Oil and Gas Accounting

Accounting for oil and gas activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of G&G seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been recognized.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For insignificant individual leasehold acquisition costs, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves, including estimates of future expirations, and pools that leasehold information with others in similar geographic areas. For prospects in areas with limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense. This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively.

At year-end 2025, we held $10.0 billion of net capitalized unproved property costs. These capitalized costs consist primarily of individually significant and pooled leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently being drilled, suspended exploratory wells and capitalized interest. Of this amount, approximately $8.7 billion is concentrated in the Lower 48 Basins, primarily the Delaware, Eagle Ford and Bakken Basins, where we have an ongoing significant and active development program. Outside of the Lower 48 Basins, the remaining $1.3 billion is primarily concentrated in Canada. Management periodically assesses our unproved property for impairment based on the results of exploration and drilling efforts and the outlook for commercialization.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or “suspended,” on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort to justify development. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of “sufficient progress” is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the expectation future market conditions will improve or new technologies will be found that would make the development economically profitable. Often, the ability to move into the development phase and record proved reserves is dependent on obtaining permits and government or coventurer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as we are actively pursuing such approvals and permits and believe they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

At year-end 2025, total suspended well costs were $243 million, compared with $196 million at year-end 2024. For additional information on suspended wells, including an aging analysis, *see Note 5*.

Proved Reserves
Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of “proved” reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company’s operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as “proved.” Our geosciences and reservoir engineering organization has policies and procedures in place consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates. See *“Supplementary Data - Oil and Gas Operations”* for additional information.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when an asset will reach the end of its economic life is based on historical 12-month first-of-month average prices and current costs. This date estimates when production will end and affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to PSCs, reported under the “economic interest” method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. We would expect reserves from these contracts to decrease when product prices rise and increase when prices decline.

The estimation of proved reserves is also important to the income statement because the proved reserve estimate for a field serves as the denominator in the unit-of-production calculation of the DD&A of the capitalized costs for that asset. At year-end 2025, the net book value of productive PP&E subject to a unit-of-production calculation was approximately $80 billion and the DD&A recorded on these assets in 2025 was approximately $11.2 billion. The estimated proved developed reserves for our consolidated operations were 4.5 billion BOE at the end of 2024 and 4.2 billion BOE at the end of 2025. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 10 percent across all calculations, before-tax DD&A in 2025 would have increased by an estimated $1,250 million.

Business Combination—Valuation of Oil and Gas Properties

For business combinations, management applies the principles of acquisition accounting under FASB ASC Topic 805 – “Business Combinations” and allocates the purchase price to assets acquired and liabilities assumed, based on their estimated fair values as of the acquisition date. Estimating the fair values involves making various assumptions, of which the most significant assumptions relate to the fair values assigned to proved and unproved oil and gas properties. For significant business combinations, management generally utilizes a discounted cash flow approach, based on market participant assumptions, and considers engaging third party valuation experts in preparing fair value estimates.

Significant inputs incorporated within the valuation include future commodity price assumptions and production profiles of reserve estimates, future operating and development costs, inflation rates, and discount rates using a market-based weighted average cost of capital determined at the time of the acquisition. When estimating the fair value of unproved properties, additional risk-weighting adjustments are applied to probable and possible reserves.

The assumptions and inputs incorporated within the fair value estimates are subject to considerable management judgment and are based on industry, market and economic conditions prevalent at the time of the acquisition. Although we based these estimates on assumptions believed to be reasonable, these estimates are inherently unpredictable and uncertain and actual results could differ. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate is recorded. Subsequent to the acquisition date, and not later than one year from the acquisition date, we record any material adjustments to the initial estimate based on new information obtained that would have existed as of the date of the acquisition. Any adjustment that arises from information obtained that did not exist as of the date of acquisition is recorded in the period the adjustment arises. *See Note 3*.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If there is an indication the carrying amount of an asset may not be recovered, a recoverability test is performed using management's assumptions for prices, volumes and future development plans. If the sum of the undiscounted cash flows before income-taxes is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment in the periods in which the determination is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for E&P assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates and prices believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, commodity prices, operating costs and capital decisions, considering all available evidence at the date of review. Differing assumptions could affect the timing and the amount of an impairment in any period.

Investments in nonconsolidated entities accounted for under the equity method are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment's carrying amount. When such a condition is judgmentally determined to be other than temporary, an impairment charge is recognized for the difference between the investment's carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee's financial condition and near-term prospects and our ability and intention to retain our investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. Since quoted market prices are usually not available, the fair value is typically based on the present value of expected future cash flows using discount rates and prices believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period.

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve plugging and abandonment of wells, removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska. Fair value is estimated using a present value approach, incorporating assumptions about estimated amounts and timing of settlements and impacts of the use of technologies. Estimating future asset removal costs requires significant judgment. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. The carrying value of our asset retirement obligation estimate is sensitive to inputs such as asset removal technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, which are all subject to change between the time of initial recognition of the liability and future settlement of our obligation.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, under the above or similar contracts, permits and regulations, we have certain environmental-related projects. These are primarily related to remediation activities required by Canada and various states within the U.S. at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. *See Note 6*.

Projected Benefit Obligations
The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. Ultimately, we will be required to fund all vested benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Projected benefit obligations are particularly sensitive to the discount rate assumption. A 100 basis-point decrease in the discount rate assumption would increase projected benefit obligations by $500 million. Benefit expense is sensitive to the discount rate and return on plan assets assumptions. A 100 basis-point decrease in the discount rate assumption would increase annual benefit expense by $50 million, while a 100 basis-point decrease in the return on plan assets assumption would increase annual benefit expense by $50 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans. We are also exposed to the possibility that lump sum retirement benefits taken from pension plans during the year could exceed the total of service and interest components of annual pension expense and trigger accelerated recognition of a portion of unrecognized net actuarial losses and gains. These benefit payments are based on decisions by plan participants and are therefore difficult to predict. In the event there is a significant reduction in the expected years of future service of present employees or the elimination of the accrual of defined benefits for some or all of their future services for a significant number of employees, we could recognize a curtailment gain or loss. *See Note 14*.

Contingencies
A number of claims and lawsuits are made against the company arising in the ordinary course of business. Management exercises judgment related to accounting and disclosure of these claims which includes losses, damages and underpayments associated with environmental remediation, tax, contracts and other legal disputes. As we learn new facts concerning contingencies, we reassess our position both with respect to amounts recognized and disclosed considering changes to the probability of additional losses and potential exposure; however, actual losses can and do vary from estimates for a variety of reasons including legal, arbitration or other third-party decisions; settlement discussions; evaluation of scope of damages; interpretation of regulatory or contractual terms; expected timing of future actions; and proportion of liability shared with other responsible parties. Estimated future costs related to contingencies are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes. For additional information on contingent liabilities, see the "Contingencies" section within "Capital Resources and Liquidity" and *Note 9*.

Income Taxes
We are subject to income taxation in numerous jurisdictions worldwide. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion, or all, of the deferred tax assets will not be realized. In assessing the need for adjustments to existing valuation allowances, we consider all available positive and negative evidence. Positive evidence includes reversals of temporary differences, forecasts of future taxable income, assessment of future business assumptions and applicable tax planning strategies that are prudent and feasible. Negative evidence includes losses in recent years as well as the forecasts of future net income (loss) in the realizable period. In making our assessment regarding valuation allowances, we weigh the evidence based on objectivity. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions and the assessment of the effects of foreign taxes on our U.S. federal income taxes (particularly as related to prevailing oil and gas prices). *See Note 15*.

We regularly assess and, if required, establish accruals for uncertain tax positions that could result from assessments of additional tax by taxing jurisdictions in countries where we operate. We recognize a tax benefit from an uncertain tax position when it is more likely than not 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, court proceedings, changes in applicable tax laws, including tax case rulings and legislative guidance, or expiration of the applicable statute of limitations. *See Note 15.*

Cautionary Statement for the Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, costs and plans, objectives of management for future operations, are forward-looking statements. Examples of forward-looking statements contained in this report include our expected production growth and outlook on the business environment generally, our expected capital budget and capital expenditures, and discussions concerning development or replacement of reserves and future dividends. You can often identify our forward-looking statements by the words "*ambition*," "*anticipate*," "*believe*," "*budget*," "*continue*," "*could*," "*effort*," "*estimate*," "*expect*," "*forecast*," "*goal*," "*guidance*," "*intend*," "*may*," "*objective*," "*outlook*," "*plan*," "*potential*," "*predict*," "*projection*," "*seek*," "*should*," "*target*," "*will*," "*would*" and similar expressions.

We based our forward-looking statements on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you these statements are not guarantees of future performance as they involve assumptions that, while made in good faith, may prove to be incorrect or inaccurate, and involve risks and uncertainties we cannot predict. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors and uncertainties, including, but not limited to, the following:

- Effects of volatile commodity prices, including prolonged periods of low commodity prices, which may adversely impact our operating results and our ability to execute on our strategy and could result in recognition of impairment charges on our long-lived assets, leaseholds and nonconsolidated equity investments.
- Global and regional changes in the demand, supply, prices, differentials or other market conditions affecting oil and gas, including changes as a result of any ongoing military conflict and the global response to such conflict; geopolitical tensions; security threats on facilities and infrastructure; global health crises; the imposition or lifting of crude oil production quotas or other actions that might be imposed by OPEC and other producing countries; or the resulting company or third-party actions in response to such changes.
- The potential for insufficient liquidity or other factors, such as those described herein, that could impact our ability to repurchase shares and declare and pay dividends, whether fixed or variable.
- Potential failures or delays in achieving expected reserve or production levels from existing and future oil and gas developments, including due to operating hazards, drilling risks and the inherent uncertainties in predicting reserves and reservoir performance.
- Reductions in our reserve replacement rates, whether as a result of significant declines in commodity prices or otherwise.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Failure to progress or complete announced and future development plans related to constructing, modifying or operating E&P and LNG facilities, or unexpected changes in costs, inflationary pressures or technical equipment related to such plans.
- Significant operational or investment changes imposed by legislative and regulatory initiatives and international agreements addressing environmental concerns, including initiatives addressing the impact of global climate change, such as limiting or reducing GHG emissions; regulations concerning hydraulic fracturing, methane emissions, flaring or water disposal; and prohibitions on commodity exports.
- Broader societal attention to and efforts to address climate change may cause substantial investment in and increased adoption of competing or alternative energy sources.
- Risks, uncertainties and high costs that may prevent us from successfully executing on our Climate-related Risk Strategy.
- Lack or inadequacy of, or disruptions in, reliable transportation for our crude oil, bitumen, natural gas, LNG and NGLs.
- Inability to timely obtain or maintain permits, including those necessary for construction, drilling and/or development, or inability to make capital expenditures required to maintain compliance with any necessary permits or applicable laws or regulations.
- Potential disruption or interruption of our operations and any resulting consequences due to accidents; extraordinary weather events; supply chain disruptions; civil unrest; political events; war; terrorism; cybersecurity threats or information technology failures, constraints or disruptions.

- Liability for remedial actions, including removal and reclamation obligations, under existing or future environmental regulations and litigation.
- Liability resulting from pending or future litigation or our failure to comply with applicable laws and regulations.
- General domestic and international economic, political and diplomatic developments, including deterioration of international trade relationships; the imposition of trade restrictions or tariffs relating to commodities and material or products (such as aluminum and steel) used in the operation of our business; expropriation of assets; changes in governmental policies relating to commodity pricing, including the imposition of price caps; sanctions; or other adverse regulations or taxation policies.
- Competition and consolidation in the oil and gas E&P industry, including competition for sources of supply, services, personnel and equipment.
- Any limitations on our access to capital or increase in our cost of capital or insurance, including as a result of illiquidity, changes or uncertainty in domestic or international financial markets, foreign currency exchange rate fluctuations or investment sentiment.
- Challenges or delays to our execution of, or successful implementation of any future asset dispositions or acquisitions we elect to pursue; potential disruption of our operations, including the diversion of management time and attention; our inability to realize anticipated cost savings or capital expenditure reductions; difficulties integrating acquired businesses and technologies; or other unanticipated changes.
- Our inability to deploy the net proceeds from any asset dispositions that are pending or that we elect to undertake in the future in the manner and timeframe we anticipate, if at all.
- The operation, financing and management of risks of our joint ventures.
- The ability of our customers and other contractual counterparties to satisfy their obligations to us, including our ability to collect payments when due from the government of Venezuela or PDVSA.
- Uncertainty as to the long-term value of our common stock.
- The factors generally described in *Part I—Item 1A* in this 2025 Annual Report on Form 10-K and any additional risks described in our other filings with the SEC.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose our cash flows or earnings to changes in commodity prices, foreign currency exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of natural gas, crude oil and related products; fluctuations in interest rates and foreign currency exchange rates; or to capture market opportunities.

Our use of derivative instruments is governed by an “Authority Limitations” document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity. The Authority Limitations document also establishes the Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks. The Chief Financial Officer and Executive Vice President, Strategy and Commercial, who reports to the Chief Executive Officer, monitors commodity price risk and risks resulting from foreign currency exchange rates and interest rates.

Commodity Price Risk

Our Commercial organization uses futures, forwards, swaps and options in various markets to accomplish the following objectives:

- Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas consumers, to floating market prices.
- Enable us to use market knowledge to capture opportunities such as moving physical commodities to more profitable locations and storing commodities to capture seasonal or time premiums. We may use derivatives to optimize these activities.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity contracts we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2025. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes or held for purposes other than trading at December 31, 2025 and 2024, was immaterial to our consolidated cash flows and net income.

Interest Rate Risk
The following table provides information about our debt instruments that are sensitive to changes in U.S. interest rates. The table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. A hypothetical 10 percent change in prevailing interest rates would not have a material impact on interest expense associated with our floating-rate debt. The fair value of the fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data. Changes to prevailing interest rates would not impact our cash flows associated with fixed-rate debt, unless we elect to repurchase or retire such debt prior to maturity.

	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2025				
2026	**$ 704**	**3.40 %**	**$ —**	**— %**
2027	**777**	**4.82**	**—**	**—**
2028	**664**	**3.78**	**—**	**—**
2029	**995**	**6.78**	**—**	**—**
2030	**1,601**	**5.17**	**—**	**—**
Remaining years	**18,323**	**5.24**	**283**	**2.40 %**
Total	**$ 23,064**		**$ 283**	
Fair value	**$ 22,415**		**$ 283**	
Year-End 2024				
2025	$ 735	3.87 %	$ —	— %
2026	704	3.40	—	—
2027	778	4.82	—	—
2028	664	3.78	—	—
2029	997	6.78	—	—
Remaining years	19,924	5.23	283	2.97 %
Total	$ 23,802		$ 283	
Fair value	$ 22,714		$ 283	

Foreign Currency Exchange Risk
We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency exchange rate changes although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year and acquisitions.

At December 31, 2025 and 2024, we had outstanding foreign currency exchange forward contracts hedging cross-border commercial activity and for purposes of mitigating our cash-related exposures. Although these forwards hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives is recorded directly in earnings. Since the gain or loss on the exchange contracts is offset by the gain or loss from remeasuring cash related balances, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 2025 or December 2024 exchange rates.

The gross notional and fair value of these positions at December 31, 2025 and 2024, were immaterial.

Item 8. Financial Statements and Supplementary Data

ConocoPhillips

Index to Financial Statements

Reports of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2025. In making this assessment, it 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, we believe the company's internal control over financial reporting was effective as of December 31, 2025.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2025, and their report is included herein.

/s/ Ryan M. Lance

Ryan M. Lance

Chairman and
Chief Executive Officer

/s/ Andrew M. O'Brien

Andrew M. O'Brien

Chief Financial Officer and
Executive Vice President,
Strategy & Commercial

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

Opinion on the Financial Statements

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 17, 2026 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

Critical Audit Matter

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

Depreciation, depletion and amortization of proved oil and gas properties, plants and equipment associated with the Lower 48 segment

Description of the Matter	At December 31, 2025, the net book value of the Company's proved oil and gas properties, plants and equipment (PP&E) associated with the Lower 48 segment was $47 billion, and depreciation, depletion and amortization (DD&A) expense associated with the Lower 48 segment was $8.1 billion for the year then ended. As described in Note 1, under the successful efforts method of accounting, DD&A of PP&E on producing hydrocarbon properties and related assets are determined by the unit-of-production method. The unit-of-production method uses proved oil and gas reserves, as estimated by the Company's internal reservoir engineers. Proved oil and gas reserves estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors. Significant judgment is required by the Company's internal reservoir engineers in evaluating the data used to estimate proved oil and gas reserves. Estimating proved oil and gas reserves also requires the selection of inputs, including historical production, oil and gas price assumptions and future operating costs assumptions, among others. Auditing the Lower 48 segment's DD&A calculation is complex because of the use of the work of the internal reservoir engineers and the evaluation of management's determination of certain inputs described above used by the internal reservoir engineers in estimating proved 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 internal controls over its processes to calculate the Lower 48 segment DD&A, including management's controls over the completeness and accuracy of significant data provided to the internal reservoir engineers for use in estimating proved oil and gas reserves associated with the Lower 48 segment. 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 proved oil and gas reserves estimates associated with the Lower 48 segment. In addition, in assessing whether we can use the work of the internal reservoir engineers, we evaluated the completeness and accuracy of the significant data and inputs described above used by the internal reservoir engineers in estimating proved oil and gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. We also tested the accuracy of the DD&A calculation associated with the Lower 48 segment, including comparing the proved oil and gas reserves amounts used in the calculation to the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1949.

Houston, Texas
February 17, 2026

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of ConocoPhillips

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related consolidated income statement, consolidated statements of comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2025, and the related notes and our report dated February 17, 2026 expressed an unqualified opinion thereon.

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

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

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

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 17, 2026

Consolidated Income Statement **ConocoPhillips**

Years Ended December 31		Millions of Dollars	
	2025	2024	2023
Revenues and other income			
Sales and other operating revenues	**$ 58,944**	54,745	56,141
Equity in earnings of affiliates	**1,335**	1,705	1,720
Gain (loss) on dispositions	**731**	51	228
Other income	**538**	452	485
Total revenues and other income	**61,548**	56,953	58,574
Costs and expenses			
Purchased commodities	**22,325**	20,012	21,975
Production and operating expenses	**10,331**	8,751	7,693
Selling, general and administrative expenses	**893**	1,158	705
Exploration expenses	**407**	355	398
Depreciation, depletion and amortization	**11,500**	9,599	8,270
Impairments	**26**	80	14
Taxes other than income taxes	**2,146**	2,087	2,074
Accretion on discounted liabilities	**378**	325	283
Interest and debt expense	**855**	783	780
Foreign currency transaction (gain) loss	**11**	(50)	92
Other expenses	**20**	181	2
Total costs and expenses	**48,892**	43,281	42,286
Income (loss) before income taxes	**12,656**	13,672	16,288
Income tax provision (benefit)	**4,668**	4,427	5,331
Net income (loss)	**$ 7,988**	9,245	10,957
Net income (loss) per share of common stock *(dollars)*			
Basic	**$ 6.36**	7.82	9.08
Diluted	**6.35**	7.81	9.06
Weighted-average common shares outstanding *(in thousands)*			
Basic	**1,252,042**	1,178,920	1,202,757
Diluted	**1,253,446**	1,180,871	1,205,675

See Notes to Consolidated Financial Statements.

Consolidated Statement of Comprehensive Income **ConocoPhillips**

Years Ended December 31		Millions of Dollars	
	2025	2024	2023
Net income (loss)	**$ 7,988**	9,245	10,957
Other comprehensive income (loss), net of tax:			
Defined benefit plans	**55**	3	55
Unrealized holding gain (loss) on securities	**5**	1	13
Foreign currency translation adjustments	**502**	(760)	197
Unrealized gain (loss) on hedging activities	**—**	(44)	62
Other comprehensive income (loss), net of tax	**562**	(800)	327
Comprehensive income (loss)	**$ 8,550**	8,445	11,284

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2025	2024
Assets			
Cash and cash equivalents	$	**6,497**	5,607
Short-term investments		**484**	507
Accounts and notes receivable (net of allowance of $4 and $7, respectively)		**5,813**	6,695
Inventories		**1,873**	1,809
Prepaid expenses and other current assets		**865**	1,029
Total current assets		**15,532**	15,647
Investments and long-term receivables		**10,185**	9,869
Net properties, plants and equipment (net of accumulated DD&A of $90,396 and $81,072, respectively)		**93,239**	94,356
Other assets		**2,983**	2,908
Total assets	$	**121,939**	122,780
Liabilities			
Accounts payable	$	**6,218**	6,044
Short-term debt		**1,020**	1,035
Accrued income and other taxes		**1,835**	2,460
Employee benefit obligations		**1,136**	1,087
Other accruals		**1,763**	1,498
Total current liabilities		**11,972**	12,124
Long-term debt		**22,424**	23,289
Asset retirement obligations and accrued environmental costs		**8,214**	8,089
Deferred income taxes		**12,237**	11,426
Employee benefit obligations		**969**	1,022
Other liabilities and deferred credits		**1,636**	2,034
Total liabilities		**57,452**	57,984
Equity			
Common stock (2,500,000,000 shares authorized at $0.01 par value) Issued (2025—2,253,518,282 shares; 2024—2,250,672,734 shares)			
Par value		**23**	23
Capital in excess of par		**77,728**	77,529
Treasury stock (at cost: 2025—1,028,350,186 shares; 2024—974,806,010 shares)		**(76,217)**	(71,152)
Accumulated other comprehensive income (loss)		**(5,911)**	(6,473)
Retained earnings		**68,864**	64,869
Total equity		**64,487**	64,796
Total liabilities and equity	$	**121,939**	122,780

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows ConocoPhillips

Years Ended December 31	Millions of Dollars			
		2025	2024	2023
Cash flows from operating activities				
Net income (loss)	$	**7,988**	9,245	10,957
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization		**11,500**	9,599	8,270
Impairments		**26**	80	14
Dry hole costs and leasehold impairments		**181**	46	162
Accretion on discounted liabilities		**378**	325	283
Deferred taxes		**549**	367	1,145
Distributions more (less) than income from equity affiliates		**200**	564	964
(Gain) loss on dispositions		**(731)**	(51)	(228)
Other		**(219)**	130	(220)
Working capital adjustments				
Decrease (increase) in accounts and notes receivable		**803**	(262)	1,333
Decrease (increase) in inventories		**(116)**	(68)	(103)
Decrease (increase) in prepaid expenses and other current assets		**(24)**	79	337
Increase (decrease) in accounts payable		**(212)**	(543)	(1,118)
Increase (decrease) in taxes and other accruals		**(527)**	613	(1,831)
Net cash provided by operating activities		**19,796**	20,124	19,965
Cash flows from investing activities				
Capital expenditures and investments		**(12,553)**	(12,118)	(11,248)
Working capital changes associated with investing activities		**546**	302	30
Acquisition of businesses, net of cash acquired		**—**	(24)	(2,724)
Proceeds from asset dispositions		**3,248**	261	632
Net sales (purchases) of investments		**(55)**	415	1,373
Other		**(22)**	14	(63)
Net cash used in investing activities		**(8,836)**	(11,150)	(12,000)
Cash flows from financing activities				
Issuance of debt		**—**	5,591	3,787
Repayment of debt		**(913)**	(4,981)	(1,379)
Issuance of company common stock		**(100)**	(78)	(52)
Repurchase of company common stock		**(5,018)**	(5,463)	(5,400)
Dividends paid		**(3,995)**	(3,646)	(5,583)
Other		**(76)**	(258)	(34)
Net cash used in financing activities		**(10,102)**	(8,835)	(8,661)
Effect of exchange rate changes on cash, cash equivalents and restricted cash		**153**	(133)	(99)
Net change in cash, cash equivalents and restricted cash		**1,011**	6	(795)
Cash, cash equivalents and restricted cash at beginning of period		**5,905**	5,899	6,694
Cash, cash equivalents and restricted cash at end of period	$	**6,916**	5,905	5,899

Restricted cash of $65 million is included in the "Prepaid expenses and other current assets" line of our Consolidated Balance Sheet as of December 31, 2025.
Restricted cash of $354 million and $298 million is included in the “Other assets” line of our Consolidated Balance Sheet at December 31, 2025, and December 31, 2024, respectively.

See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Equity **ConocoPhillips**

	Millions of Dollars						
	Common Stock						
		Par Value	Capital in Excess of Par	Treasury Stock	Accum. Other Comprehensive Income (Loss)	Retained Earnings	Total
Balances at December 31, 2022	$	21	61,142	(60,189)	(6,000)	53,029	48,003
Net income (loss)						10,957	10,957
Other comprehensive income (loss)					327		327
Dividends declared							
Ordinary ($2.11 per share of common stock)						(2,550)	(2,550)
Variable return of cash ($1.80 per share of common stock)						(2,170)	(2,170)
Repurchase of company common stock				(5,400)			(5,400)
Excise tax on share repurchases				(50)			(50)
Distributed under benefit plans			161				161
Other				(1)		2	1
Balances at December 31, 2023	$	21	61,303	(65,640)	(5,673)	59,268	49,279
Net income (loss)						9,245	9,245
Other comprehensive income (loss)					(800)		(800)
Dividends declared							
Ordinary ($2.52 per share of common stock)						(2,942)	(2,942)
Variable return of cash ($0.60 per share of common stock)						(704)	(704)
Acquisition of Marathon Oil		2	16,037				16,039
Repurchase of company common stock				(5,463)			(5,463)
Excise tax on share repurchases				(50)			(50)
Distributed under benefit plans			189				189
Other				1		2	3
Balances at December 31, 2024	$	23	77,529	(71,152)	(6,473)	64,869	64,796
Net income (loss)						**7,988**	**7,988**
Other comprehensive income (loss)					**562**		**562**
Dividends declared							
Ordinary ($3.18 per share of common stock)						**(3,995)**	**(3,995)**
Repurchase of company common stock				**(5,018)**			**(5,018)**
Excise tax on share repurchases				**(47)**			**(47)**
Distributed under benefit plans			**199**				**199**
Other				**—**		**2**	**2**
Balances at December 31, 2025	**$**	**23**	**77,728**	**(76,217)**	**(5,911)**	**68,864**	**64,487**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1—Accounting Policies

- **Consolidation Principles and Investments**—Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and, if applicable, variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates' operating and financial policies. When we do not have the ability to exert significant influence, the investment is measured at fair value except when the investment does not have a readily determinable fair value. For those exceptions, it will be measured at cost minus impairment, plus or minus observable price changes in orderly transactions for an identical or similar investment of the same issuer. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. We manage our operations through five operating segments, defined by geographic region: Alaska; Lower 48; Canada; Europe, Middle East and North Africa; and Asia Pacific. *See Note 22*.

- **Foreign Currency Translation**—Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income (loss) in common stockholders' equity. Foreign currency transaction gains and losses are included in current earnings. Some of our foreign operations use their local currency as the functional currency.

- **Use of Estimates**—The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. Actual results could differ from these estimates.

- **Revenue Recognition**—Revenues associated with the sales of crude oil, bitumen, natural gas, NGLs, LNG and other items are recognized at the point in time when the customer obtains control of the asset. In evaluating when a customer has control of the asset, we primarily consider whether the transfer of legal title and physical delivery has occurred, whether the customer has significant risks and rewards of ownership and whether the customer has accepted delivery and a right to payment exists. These products are typically sold at prevailing market prices. We allocate variable market-based consideration to deliveries (performance obligations) in the current period as that consideration relates specifically to our efforts to transfer control of current period deliveries to the customer and represents the amount we expect to be entitled to in exchange for the related products. Payment is typically due within 30 days or less.

  Transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into "in contemplation" of one another, are combined and reported net (i.e., on the same income statement line).

- **Shipping and Handling Costs**—We typically incur shipping and handling costs prior to control transferring to the customer and account for these activities as fulfillment costs. Accordingly, we include shipping and handling costs in production and operating expenses for production activities. Transportation costs related to marketing activities are recorded in purchased commodities. Freight costs billed to customers are treated as a component of the transaction price and recorded as a component of revenue when the customer obtains control.

- **Cash Equivalents**—Cash equivalents are highly liquid, short-term investments that are readily convertible to known amounts of cash and have original maturities of 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Short-Term Investments**—Short-term investments include investments in bank time deposits and marketable securities (commercial paper and government obligations) which are carried at cost plus accrued interest and have original maturities of greater than 90 days but within one year or when the remaining maturities are within one year. We also invest in financial instruments classified as available for sale debt securities which are carried at fair value. Those instruments are included in short-term investments when they have remaining maturities of one year or less, as of the balance sheet date.

- **Long-Term Investments in Debt Securities**—Long-term investments in debt securities includes financial instruments classified as available for sale debt securities with remaining maturities greater than one year as of the balance sheet date. They are carried at fair value and presented within the "Investments and long-term receivables" line of our consolidated balance sheet.

- **Inventories**—We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. The majority of our commodity-related inventories are recorded at cost using the LIFO basis. We measure these inventories at the lower-of-cost-or-market in the aggregate. Any necessary lower-of-cost-or-market write-downs at year end are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/nonrecurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, such as tubular goods and well equipment, are valued using various methods, including the weighted-average-cost method and the FIFO method, consistent with industry practice.

- **Fair Value Measurements**—Assets and liabilities measured at fair value and required to be categorized within the fair value hierarchy are categorized into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

- **Derivative Instruments**—Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives not accounted for as hedges are recognized immediately in earnings. We do not apply hedge accounting to our commodity derivative instruments.

- **Oil and Gas Exploration and Development**—Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  Property Acquisition Costs—Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption PP&E. Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon achievement of all conditions necessary for reserves to be classified as proved, the associated leasehold costs are reclassified to proved properties.

  Exploratory Costs—Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field or while we seek government or coventurer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas resources are designated as proved reserves.

  Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as dry holes when it judges the potential field does not warrant further investment in the near term. *See Note 5.*

  Development Costs—Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

  Depletion and Amortization—Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved developed and proved undeveloped oil and gas reserves. Amortization of development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Capitalized Interest**—Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Depreciation and Amortization**—Depreciation and amortization of PP&E on producing hydrocarbon properties and SAGD facilities are determined by the unit-of-production method. Depreciation and amortization of all other PP&E are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment**—Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If there is an indication the carrying amount of an asset may not be recovered, a recoverability test is performed using management's assumptions for prices, volumes and future development plans. If the sum of the undiscounted cash flows before income-taxes is less than the carrying value of the asset group, the carrying value is written down to estimated fair value and reported as an impairment in the period in which the determination is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets—generally on a field-by-field basis for E&P assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates and prices believed to be consistent with those used by principal market participants, or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible.

  The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, commodity prices, operating costs and capital decisions, considering all available evidence at the date of review. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable and possible reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation.

  Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

- **Maintenance and Repairs**—Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- **Property Dispositions**—When complete units of depreciable property are sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in the "Gain (loss) on dispositions" line of our consolidated income statement. When partial units of depreciable property are sold or retired which do not significantly alter the DD&A rate, the asset cost and accumulated depreciation are eliminated such that no gain or loss is recorded.

- **Asset Retirement Obligations and Environmental Costs**—The fair value of legal obligations to retire and remove long-lived assets are recorded in the period in which the obligation is incurred (typically when the asset is installed at the production location). Fair value is estimated using a present value approach, incorporating assumptions about estimated amounts and timing of settlements and impacts of the use of technologies. *See Note 6*.

  Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired through a business combination, which we record on a discounted basis) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is probable and estimable.

- **Impairment of Investments in Nonconsolidated Entities**—Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates and prices believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

- **Guarantees**—The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

- **Share-Based Compensation**—We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. We have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **Income Taxes**—Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income and temporary differences related to the cumulative translation adjustment considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest and debt expense, and penalties related to unrecognized tax benefits are reflected in production and operating expenses.

- **Taxes Collected from Customers and Remitted to Governmental Authorities**—Sales and value-added taxes are recorded net.

- **Net Income (Loss) Per Share of Common Stock**—Basic net income (loss) per share is calculated using the two-class method. Under the two-class method, all earnings (distributed and undistributed) are allocated to common stock (including fully vested stock and unit awards that have not yet been issued as common stock) and participating securities. ConocoPhillips grants Restricted Stock Units (RSUs) under its share-based compensation programs, the majority of which entitle recipients to receive non-forfeitable dividends during the vesting period on a basis equivalent to dividends paid to holders of the company's common stock. *See Note 14*. These unvested RSUs meet the definition of participating securities based on their respective rights to receive non-forfeitable dividends and are treated as a separate class of securities in computing basic EPS. Participating securities are not included as incremental shares in computing diluted EPS. Diluted EPS includes the potential impact of contingently issuable shares, including awards which require future service as a condition of delivery of the underlying common stock. Diluted EPS is calculated under both the two-class and treasury stock methods, and the more dilutive amount is reported. Diluted net loss per share does not assume conversion or exercise of securities that would have an antidilutive effect. Treasury stock is excluded from the daily weighted-average number of common shares outstanding in both calculations. *See Note 21*.

Note 2—Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2025	2024
Crude oil and products	$	**1,000**	907
Materials and supplies		**873**	902
Total inventories	$	**1,873**	1,809
Inventories valued on the LIFO basis	$	**609**	578

The estimated excess of current replacement cost over LIFO cost of inventories was approximately $65 million and $113 million at December 31, 2025 and 2024, respectively.

Note 3—Acquisitions and Dispositions

All gains or losses on asset dispositions are reported before-tax and are included net in the “Gain (loss) on dispositions” line on our consolidated income statement. Cash proceeds and payments are included in the “Cash flows from investing activities” section of our consolidated statement of cash flows except for cash payments associated with a contingent consideration arrangement that are included in the "Cash flows from financing activities" section.

2025

Assets Sold

In the second quarter of 2025, we sold our interests in the Ursa and Europa fields and Ursa Oil Pipeline Company LLC for net proceeds of $699 million. We recognized a $274 million before-tax and $266 million after-tax gain for this transaction, inclusive of the reduction of our valuation allowance recognized in the first quarter of 2025. At the time of disposition, these assets, in our Lower 48 segment, had a net carrying value of $444 million, comprised of $536 million of assets, primarily $522 million of PP&E, and $92 million of liabilities, primarily related to noncurrent AROs. For tax-related impacts of this disposition, *see Note 15.*

In the fourth quarter of 2025, we sold Lower 48 assets in the Anadarko basin for net proceeds of $1.2 billion, after customary closing adjustments. At the time of the disposition, these assets had a net carrying value of approximately $1.2 billion, comprised primarily of PP&E.

Additionally, during 2025, we sold our interests in other noncore assets in the Lower 48 segment for $1.1 billion and recognized a $404 million before-tax and $310 million after-tax net gain. Our interests in the disposed assets had an aggregate net carrying value of $719 million, comprised of $770 million of assets, primarily related to $645 million of PP&E and $51 million of liabilities related to noncurrent AROs.

2024

Acquisition of Marathon Oil Corporation (Marathon Oil)

In November 2024, we completed our acquisition of Marathon Oil, an independent oil and gas exploration and production company with operations across the Lower 48 and in Equatorial Guinea. At close, the transaction was valued at $16.5 billion, which primarily represented 0.255 shares of ConocoPhillips common stock exchanged for each outstanding share of Marathon Oil common stock.

Total fair value		Millions of Dollars
Value of ConocoPhillips common stock issued*		15,972
Cash transferred at close**		451
Value attributable to Marathon Oil share-based awards		67
Other liabilities incurred***		17
Total fair value	**$**	**16,507**

**Represents the fair value of approximately 143 million shares of ConocoPhillips common stock issued to Marathon Oil stockholders. The fair value is based on the number of eligible shares of Marathon Oil common stock at a 0.255 exchange ratio and ConocoPhillips' average stock price on November 22, 2024, which was $111.93.*
***Cash transferred at close primarily represents funds contributed to Marathon Oil for repayment of Marathon Oil's estimated commercial paper liabilities as of the closing date.*
****Liabilities incurred are related to cash settled share-based awards and payment of cash in lieu of fractional Marathon Oil shares outstanding. These liabilities were settled prior to the end of 2024.*

The transaction was accounted for as a business combination under FASB Topic ASC 805 using the acquisition method, which requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. In the fourth quarter of 2025, we finalized the allocation of the purchase price to specific assets and liabilities. It was based on the fair value of the final consideration and the conclusion of the fair value determination of long-lived assets and all other assets acquired and liabilities assumed.

Oil and gas properties were valued using a discounted cash flow approach incorporating market participant and internally generated price assumptions; production profiles; and operating and development cost assumptions. Debt assumed in the acquisition was valued based on observable market prices. The fair values of accounts receivable, accounts payable, and most other current assets and current liabilities were determined to be equivalent to the carrying value due to their short-term nature. The acquisition, valued at $16.5 billion, was allocated to the identifiable assets and liabilities based on their estimated fair values as of the acquisition date of November 22, 2024.

Assets acquired		Millions of Dollars
Cash and cash equivalents	$	385
Accounts receivable, net		976
Inventories		302
Investments and long-term receivables		562
Net properties, plants and equipment		24,215
Other assets		215
Total assets acquired	**$**	**26,655**
Liabilities assumed		
Accounts payable	$	1,183
Accrued income and other taxes		201
Employee benefit obligations		187
Long-term debt		4,719
Asset retirement obligations		781
Deferred income taxes		2,471
Other liabilities		606
Total liabilities assumed	**$**	**10,148**
Net assets acquired	**$**	**16,507**

With the completion of the transaction, we acquired proved properties of approximately $13.2 billion, with $12.1 billion in Lower 48 and $1.1 billion in Equatorial Guinea, and unproved properties of $10.8 billion in Lower 48.

We have recognized approximately $587 million of transaction-related costs, the majority of which were expensed in the fourth quarter of 2024. These non-recurring costs related primarily to employee severance and related benefits, fees paid to advisors and the settlement of share-based awards for certain Marathon Oil employees based on the terms of the Merger Agreement. These transaction-related costs included $334 million of employee severance expense. *See Note 14*.

For the year ended December 31, 2024, "Total revenues and other income" and "Net income (loss)" associated with the acquired assets were $677 million and income of $66 million, respectively.

Alaska Acquisition
In the fourth quarter of 2024, after exercising our preferential rights, we completed an acquisition that increased our working interest by approximately 5 percent in the Kuparuk River Unit and approximately 0.4 percent in the Prudhoe Bay Unit from Chevron U.S.A. Inc. and Union Oil Company of California for $296 million, before customary adjustments. The transaction was accounted for as an asset acquisition, with the consideration allocated primarily to PP&E.

2023
Surmont Acquisition
In October 2023, we completed our acquisition of the remaining 50 percent working interest in Surmont, an asset in our Canada segment, from TotalEnergies EP Canada Ltd. Following the acquisition, we own 100 percent working interest in Surmont. The final consideration for the all-cash transaction was $3.0 billion (CAD $4.1 billion) after customary adjustments:

Fair value of consideration	Millions of Dollars
Cash paid	$ 2,635
Contingent consideration	320
Total consideration	**$ 2,955**

For information related to the contingent consideration arrangement, *see Note 11.*

The transaction was accounted for as a business combination under FASB Topic ASC 805 using the acquisition method, which requires assets acquired and liabilities assumed to be measured at their acquisition date fair values. By the end of the first quarter of 2024, we finalized the allocation of the purchase price to specific assets and liabilities. It was based on the fair value of the final consideration and the conclusion of the fair value determination of long-lived assets and all other assets acquired and liabilities assumed.

Oil and gas properties were valued using a discounted cash flow approach incorporating market participant and internally generated price assumptions, production profiles and operating and development cost assumptions. The fair values of other assets acquired and liabilities assumed, which included accounts receivable, accounts payable, and most other current assets and current liabilities, were determined to be equivalent to the carrying value due to their short-term nature. The total consideration of $3.0 billion was allocated to the identifiable assets and liabilities based on their fair values as of the acquisition date of October 4, 2023.

Recognized amounts of identifiable assets acquired and liabilities assumed	Millions of Dollars
Oil and gas properties	3,082
Asset retirement obligations	(112)
Other	(15)
Total identifiable net assets	**$ 2,955**

With the completion of the transaction, we acquired proved and unproved properties of approximately $2.9 billion and $0.2 billion, respectively.

In anticipation of the acquisition, we entered into, and settled, various foreign exchange forward contracts to purchase CAD. For the year ended December 31, 2023, we recognized a loss of $112 million in the "Foreign currency transaction (gain) loss" line on our consolidated income statement associated with these forward contracts. The related cash flows are included within "Cash flows from investing activities" on our consolidated statement of cash flows.

From the acquisition date through December 31, 2023, "Total revenues and other income" and "Net income (loss)" associated with the acquired assets were $572 million and $119 million, respectively.

Supplemental Pro Forma (unaudited)

The following tables summarize the unaudited supplemental pro forma financial information combining the consolidated income statement of ConocoPhillips with assets acquired as shown for the year ended December 31, 2024 and 2023, as if we had completed the acquisition of Marathon Oil on January 1, 2023 and the remaining working interest in Surmont on January 1, 2022, respectively.

	Millions of Dollars		
	Year Ended December 31, 2024		
	As reported	Pro forma Marathon Oil	Pro forma Combined
Total revenues and other income	$ 56,953	6,168	63,121
Net income (loss)	9,245	1,312	10,557
Earnings per share:			
Basic net income (loss)	$ 7.82		8.06
Diluted net income (loss)	7.81		8.05

	Millions of Dollars			
	Year Ended December 31, 2023			
	As reported	Pro forma Surmont	Pro forma Marathon Oil	Pro forma Combined
Total revenues and other income	$ 58,574	2,561	6,705	67,840
Net income (loss)	10,957	501	1,657	13,115
Earnings per share:				
Basic net income (loss)	$ 9.08			9.72
Diluted net income (loss)	9.06			9.70

The unaudited supplemental pro forma financial information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the Surmont and Marathon Oil transactions been completed on January 1, 2022, and January 1, 2023, respectively, nor is it necessarily indicative of future operating results of the combined entity. The pro forma results do not include cost savings anticipated as a result of the transaction. The pro forma results include adjustments which relate primarily to DD&A, which is based on the unit-of-production method, resulting from the purchase price allocated to oil and gas properties as well as adjustments for the timing of transaction costs and tax impacts. We believe the estimates and assumptions are reasonable, and the relative effects of the transaction are properly reflected.

QatarEnergy LNG NFS(3) (NFS3)

During 2022, we were awarded a 25 percent interest in NFS3, a new joint venture with QatarEnergy, to participate in the North Field South (NFS) LNG project in Qatar. Formation of NFS3 closed during 2023. NFS3 has a 25 percent interest in the NFS project and is reported as an equity method investment in our Europe, Middle East and North Africa segment. *See Note 4.*

Port Arthur Liquefaction Holdings, LLC (PALNG)

During 2023, we acquired a 30 percent interest in PALNG, a joint venture for the development of a large-scale LNG facility for the first phase of the Port Arthur LNG project ("Phase 1"). Sempra PALNG Holdings, LLC owns the remaining 70 percent interest in the joint venture. PALNG is reported as an equity method investment in our Corporate and Other segment. *See Note 4.*

Note 4—Investments, Loans and Long-Term Receivables

Components of investments and long-term receivables at December 31 were:

	Millions of Dollars	
	2025	2024
Equity investments	$ **8,833**	8,611
Long-term receivables	**110**	113
Long-term investments in debt securities	**1,148**	1,055
Other investments	**94**	90
Total	$ **10,185**	9,869

Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2025, included:

- APLNG—47.5 percent owned joint venture with Origin Energy (27.5 percent) and Sinopec (25 percent)—to produce CBM from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- PALNG—30 percent owned joint venture with Sempra PALNG Holdings, LLC for the development of a large-scale LNG facility for the first phase of the Port Arthur LNG project ("Phase 1"). *See Note 3.*
- QatarEnergy LNG N(3) (N3)—30 percent owned joint venture with affiliates of QatarEnergy (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent)—produces and liquefies natural gas from Qatar’s North Field, as well as exports LNG.
- QatarEnergy LNG NFE(4) (NFE4)—25 percent owned joint venture with affiliates of QatarEnergy (70 percent) and China National Petroleum Corporation (5 percent)—participant in the North Field East LNG project.
- NFS3—25 percent owned joint venture with an affiliate of QatarEnergy (75 percent)—participant in the North Field South LNG project. *See Note 3.*

Summarized 100 percent earnings information for equity method investments in affiliated companies, combined, was as follows:

	Millions of Dollars		
	2025	2024	2023
Revenues	$ **13,607**	15,286	15,314
Income (loss) before income taxes	**5,022**	6,446	6,301
Net income (loss)	**3,441**	4,389	4,214

Summarized 100 percent balance sheet information for equity method investments in affiliated companies, combined, was as follows:

	Millions of Dollars	
	2025	2024
Current assets	$ **5,793**	4,608
Noncurrent assets	**43,935**	41,417
Current liabilities	**3,521**	3,829
Noncurrent liabilities	**18,815**	16,947

Our share of income taxes incurred directly by an equity method investee is reported in equity in earnings of affiliates, and as such is not included in income taxes on our consolidated financial statements.

At December 31, 2025, retained earnings included $112 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $1,531 million, $2,283 million and $2,684 million in 2025, 2024 and 2023, respectively.

APLNG

APLNG is a joint venture focused on producing CBM from the Bowen and Surat basins in Queensland, Australia. Natural gas is sold to domestic customers and LNG is processed and exported to Asia Pacific markets. Our investment in APLNG gives us access to CBM resources in Australia and enhances our LNG position. The majority of APLNG LNG is sold under two long-term sales and purchase agreements, supplemented with sales of additional LNG cargoes targeting the Asia Pacific markets. Origin Energy, an integrated Australian energy company, is the operator of APLNG's production and pipeline system, while we operate the LNG facility.

In 2012, APLNG executed an $8.5 billion project finance facility that became non-recourse following financial completion in 2017. The facility is currently composed of a financing agreement with the Export-Import Bank of the United States, a commercial bank facility and two United States Private Placement note facilities. APLNG principal and interest payments commenced in March 2017 and are scheduled to occur bi-annually until September 2030. At December 31, 2025, a balance of $3.4 billion was outstanding on the facilities. *See Note 8*.

At December 31, 2025, the carrying value of our equity method investment in APLNG was approximately $4.9 billion.

PALNG

PALNG is a joint venture for the development of a large-scale LNG facility. At December 31, 2025, the carrying value of our equity method investment in PALNG was approximately $1.6 billion. *See Note 3*.

Investments in Qatar

N3

N3 is a 30 percent owned joint venture in an integrated large-scale LNG project. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Sabine Pass, Texas, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from N3. Currently, the LNG from N3 is being sold to markets outside of the U.S.

NFE4

NFE4 is a joint venture participating in the NFE LNG project. NFE4 has a 12.5 percent interest in the NFE project.

We have concluded NFE4 is a VIE as it currently requires advances from the joint venture participants to fund the project. We are not the primary beneficiary of the VIE because we do not have the power to direct the activities that most significantly impact economic performance of NFE4, which involve activities related to the production and commercialization of natural gas, as well as LNG processing and export marketing. As a result, we do not consolidate NFE4, and it is accounted for under the equity method. As of December 31, 2025, the carrying value of our equity is included in the total carrying value of our equity method investments in Qatar. This equity together with the guarantee is the only financial support that we have provided NFE4. *See Note 8*.

NFS3

NFS3 is a joint venture participating in the NFS LNG project. NFS3 has a 25 percent interest in the NFS project. *See Note 3*.

At December 31, 2025, the carrying value of our equity method investments in Qatar was approximately $1.7 billion.

Loans

As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans to certain affiliated and non-affiliated companies.

At December 31, 2025, there were no outstanding loans to affiliated companies.

Note 5—Suspended Wells and Exploration Expenses

The following table reflects the net changes in suspended exploratory well costs during 2025, 2024 and 2023:

		Millions of Dollars		
		2025	2024	2023
Beginning balance	**$**	**196**	184	527
Additions pending the determination of proved reserves		**113**	32	—
Reclassifications to proved properties		**—**	(2)	(285)
Sales of suspended wells		**(30)**	—	—
Charged to dry hole expense		**(36)**	(18)	(58)
Ending balance	**$**	**243**	196	184

The following table provides an aging of suspended well balances at December 31:

		Millions of Dollars		
		2025	2024	2023
Exploratory well costs capitalized for a period of one year or less	**$**	**110**	33	—
Exploratory well costs capitalized for a period greater than one year		**133**	163	184
Ending balance	**$**	**243**	196	184
Number of projects with exploratory well costs capitalized for a period greater than one year		**13**	13	14

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2025:

		Millions of Dollars			
			Suspended Since		
		Total	2021-2024	2018-2020	2017 and Prior
PL891—Norway[(1)]		31	—	31	—
West Willow—Alaska[(2)]		30	—	30	—
Narwhal Trend—Alaska[(1)]		25	—	25	—
Montney—Canada[(2)]		15	7	8	—
Other of $10 million or less each[(1)(2)]		32	4	—	28
Total	$	133	11	94	28

(1) Appraisal drilling complete; costs being incurred to assess development.

(2) Additional appraisal wells planned.

Exploration Expenses
The charges discussed below are included in the “Exploration expenses” line on our consolidated income statement.

2025
We divested certain Lower 48 offshore interests in partner-operated assets, which included $30 million of suspended wells costs.

We recognized dry hole expenses of $80 million in our Asia Pacific segment, which included $36 million related to certain previously suspended wells that were capitalized for a period greater than one year.

2024
In our Europe, Middle East and North Africa segment, we recorded approximately $40 million before-tax as dry hole expenses, which included $22 million for two partner-operated exploration wells in the Alvheim area in the Norwegian sector of the North Sea, and $18 million for the Busta suspended discovery well on license PL782S in the North Sea.

2023
In our Europe, Middle East and North Africa segment, after further evaluation we recognized a before-tax expense of $37 million for dry hole costs associated with the suspended Warka discovery well, drilled in 2020, on license PL1009 in the Norwegian Sea.

In our Alaska segment, we recorded a before-tax expense of approximately $31 million for dry hole costs associated with the Bear-1 exploration well.

Note 6—Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

		Millions of Dollars	
		2025	2024
Asset retirement obligations	$	**8,364**	8,215
Accrued environmental costs		**220**	206
Total asset retirement obligations and accrued environmental costs		**8,584**	8,421
Asset retirement obligations and accrued environmental costs due within one year*		**(370)**	(332)
Long-term asset retirement obligations and accrued environmental costs	$	**8,214**	8,089

**Classified as a current liability on the balance sheet under "Other accruals."*

Asset Retirement Obligations

We record the fair value of a liability for an ARO when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset. If in subsequent periods, our estimate of this liability changes, we will record an adjustment to both the liability and PP&E. Changes to estimated liabilities for assets that are no longer producing are recorded as impairment.

We have numerous AROs we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations involve plugging and abandonment of wells and removal and disposal of offshore oil and gas platforms around the world, as well as oil and gas production facilities and pipelines in Alaska.

During 2025 and 2024, our overall ARO changed as follows:

		Millions of Dollars	
		2025	2024
Balance at January 1	$	**8,215**	7,227
Accretion of discount		**366**	319
New obligations, including acquisitions		**162**	926
Changes in estimates of existing obligations		**(150)**	140
Spending on existing obligations		**(259)**	(182)
Property dispositions		**(186)**	(6)
Foreign currency translation		**216**	(209)
Balance at December 31	$	**8,364**	8,215

Accrued Environmental Costs

Total accrued environmental costs at December 31, 2025 and 2024, were $220 million and $206 million, respectively.

We had accrued environmental costs of $142 million and $139 million at December 31, 2025 and 2024, respectively, related to remediation activities in the U.S. and Canada. We had also accrued in Corporate and Other $68 million and $56 million of environmental costs associated with sites no longer in operation at December 31, 2025 and 2024, respectively. In addition, December 31, 2025 and 2024, included a $10 million and $11 million accrual, respectively, where the company has been named a potentially responsible party under the CERCLA, or similar state laws. Accrued environmental liabilities are expected to be paid over periods extending up to 30 years.

Expected expenditures for environmental obligations acquired in various business combinations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $119 million at December 31, 2025. The total expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are $133 million.

Note 7—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2025	2024
2.4% Notes due 2025	**—**	366
8.2% Debentures due 2025	**—**	134
3.35% Notes due 2025	**—**	199
6.875% Debentures due 2026	**67**	67
7.8% Debentures due 2027	**120**	120
4.4% Notes due 2027	**422**	424
3.75% Notes due 2027	**196**	196
4.3% Notes due 2028	**223**	223
7.375% Debentures due 2029	**66**	66
7.0% Debentures due 2029	**95**	95
5.3% Notes due 2029	**84**	86
6.95% Notes due 2029	**705**	705
4.7% Notes due 2030	**1,350**	1,350
8.125% Notes due 2030	**207**	207
2.4% Notes due 2031	**227**	227
7.2% Notes due 2031	**447**	447
7.25% Notes due 2031	**268**	268
7.4% Notes due 2031	**232**	232
4.85% Notes due 2032	**650**	650
6.8% Notes due 2032	**180**	180
5.9% Notes due 2032	**505**	505
5.05% Notes due 2033	**1,000**	1,000
5.7% Notes due 2034	**103**	103
4.15% Notes due 2034	**246**	246
5.0% Notes due 2035	**1,250**	1,250
5.95% Notes due 2036	**326**	326
5.951% Notes serially maturing 2022 through 2037	**541**	573
6.6% Notes due 2037	**335**	335
5.9% Notes due 2038	**350**	350
6.5% Notes due 2039	**1,588**	1,588
3.758% Notes due 2042	**785**	785
4.3% Notes due 2044	**750**	750
5.2% Notes due 2045	**186**	186
5.95% Notes due 2046	**329**	329
7.9% Debentures due 2047	**60**	60
4.875% Notes due 2047	**319**	319
4.85% Notes due 2048	**219**	219
3.8% Notes due 2052	**1,100**	1,100
5.3% Notes due 2053	**1,100**	1,100
5.55% Notes due 2054	**1,000**	1,000
5.5% Notes due 2055	**1,300**	1,300
4.025% Notes due 2062	**1,770**	1,770
5.7% Notes due 2063	**700**	700
5.65% Notes due 2065	**650**	650
Marine Terminal Revenue Refunding Bonds due 2031 at 1.23% – 5.05% during 2025 and 1.78% – 4.80% during 2024	**265**	265

Industrial Development Bonds due 2035 at 1.23% – 5.05% during 2025 and 1.78% – 4.22% during 2024		**18**	18
St. John the Baptist Parish, State of Louisiana—Revenue Refunding Bonds due 2037[1]: $200 at 2.20%, $200 at 2.375%, $200 at 4.05%, $400 at 3.30%[1]		**1,000**	1,000
Other		**13**	16
Debt at face value		**23,347**	24,085
Finance leases		**801**	940
Net unamortized premiums, discounts and debt issuance costs		**(704)**	(701)
Total debt		**23,444**	24,324
Short-term debt		**(1,020)**	(1,035)
Long-term debt	**$**	**22,424**	23,289

[1]*Future mandatory purchase dates for these bonds: July 1, 2026 for the 2.20% bonds of $200 million, 2.375% bonds of $200 million, 4.05% bonds of $200 million and July 3, 2028 for the 3.30% bonds of $400 million. Subsequent to the mandatory purchase dates, we will also have the right to remarket these bonds any time up to the 2037 maturity date.*

The principal amounts of long-term debt, excluding finance lease obligations, maturing in 2026 through 2030 are: $713 million, of which $600 million are municipal bonds we intend to remarket, $786 million, $670 million, $992 million and $1,599 million, respectively.

2025

In 2025, the company retired $0.7 billion principal amount of debt at maturity, consisting of $0.2 billion of our 3.35% Notes, $0.4 billion of our 2.4% Notes and $0.1 billion of our 8.2% Debentures.

2024

In the fourth quarter of 2024, we acquired Marathon Oil and assumed its outstanding debt upon close. Shortly thereafter, we launched and completed concurrent debt transactions consisting of: tender offers to repurchase certain existing Marathon Oil and ConocoPhillips debt for cash (with priority for Marathon Oil debt assumed), an obligor exchange offer to retire certain Marathon Oil debt in exchange for new ConocoPhillips debt, new debt issuances to fund the repurchase tender offers and the remarketing of available municipal bonds. *See Note 3.*

<u>Marathon Oil Debt Assumed at Fair Value</u>

As part of the acquisition, we assumed Marathon Oil's publicly traded debt, with an outstanding principal balance of $4.6 billion, which was recorded at fair value of $4.7 billion. *See Note 3.*

- 4.4% Notes due 2027 with principal amount of $1,000 million
- 5.3% Notes due 2029 with principal amount of $600 million
- 6.8% Notes due 2032 with principal amount of $550 million
- 5.7% Notes due 2034 with principal amount of $600 million
- 6.6% Notes due 2037 with principal amount of $750 million
- 5.2% Notes due 2045 with principal amount of $500 million
- St. John the Baptist Parish, State of Louisiana—Revenue Refunding Bonds due 2037 with future mandatory purchase dates of July 1, 2026:
    - 2.20% Bonds with principal amount of $200 million
    - 2.375% Bonds with principal amount of $200 million
    - 4.05% Bonds with principal amount of $200 million

Repurchase Offers

In December 2024, we completed tender offers through which we repurchased a total of $3,768 million in aggregate principal amount of debt as listed below. We paid premiums above face value of $283 million to repurchase these debt instruments.

Marathon Oil Debt Repurchased:

- 4.4% Notes due 2027 partial repurchase of $576 million
- 5.3% Notes due 2029 partial repurchase of $514 million
- 6.8% Notes due 2032 partial repurchase of $370 million
- 5.7% Notes due 2034 partial repurchase of $497 million
- 6.6% Notes due 2037 partial repurchase of $415 million
- 5.2% Notes due 2045 partial repurchase of $314 million

ConocoPhillips Debt Repurchased:

- 7.8% Debentures due 2027 with principal amount of $203 million (partial repurchase of $83 million)
- 7.0% Debentures due 2029 with principal amount of $112 million (partial repurchase of $17 million)
- 7.375% Debentures due 2029 with principal amount of $92 million (partial repurchase of $26 million)
- 6.95% Notes due 2029 with principal amount of $1,195 million (partial repurchase of $490 million)
- 8.125% Notes due 2030 with principal amount of $390 million (partial repurchase of $183 million)
- 7.4% Notes due 2031 with principal amount of $382 million (partial repurchase of $151 million)
- 7.25% Notes due 2031 with principal amount of $400 million (partial repurchase of $132 million)

Exchange Offer

Concurrently in December 2024, we completed a debt exchange offer through which $863 million in aggregate principal of existing Marathon Oil notes were tendered and accepted in exchange for $862 million of new ConocoPhillips notes. The debt exchange offers were treated as debt modifications for accounting purposes resulting in a portion of the unamortized debt discount and premiums of the existing notes being allocated to the new notes on the settlement dates of the exchange offers. No premiums were paid to bondholders in this exchange offer.

The notes tendered and accepted in the exchange offers were:

- 4.4% Notes due 2027 partial exchange of $228 million
- 5.3% Notes due 2029 partial exchange of $59 million
- 6.8% Notes due 2032 partial exchange of $102 million
- 5.7% Notes due 2034 partial exchange of $63 million
- 6.6% Notes due 2037 partial exchange of $259 million
- 5.2% Notes due 2045 partial exchange of $151 million

New Debt Issuance

In December 2024, we issued new debt of $5.2 billion through our universal shelf registration statement and prospectus supplement consisting of the following new notes and used the proceeds to repurchase existing debt as discussed:

- 4.7% Notes due 2030 with principal of $1,350 million
- 4.85% Notes due 2032 with principal of $650 million
- 5.0% Notes due 2035 with principal of $1,250 million
- 5.5% Notes due 2055 with principal of $1,300 million
- 5.65% Notes due 2065 with principal of $650 million

Municipal Bonds Reoffering and Issuance

We completed a $400 million remarketing of sub-series 2017C bonds that are part of the $1 billion St. John the Baptist Parish, State of Louisiana—Revenue Refunding Bonds Series 2017. The bonds are subject to an interest rate of 3.30% and a mandatory purchase date of July 3, 2028.

As a result of the concurrent debt transactions as described above, we recognized a net loss on debt extinguishments of $173 million which is included in the "Other expenses" line on our consolidated income statement.

Other Debt Activity

Apart from the concurrent debt transactions discussed above, in November 2024, the company retired $265 million principal amount of our 3.35% Notes at maturity and in March 2024, the company retired $461 million principal amount of our 2.125% Notes at maturity.

Revolving Credit Facility and Credit Rating Information

In February 2025, we refinanced our revolving credit facility maintaining a total aggregate principal amount of $5.5 billion and extended the expiration to February 2030. Our revolving credit facility may be used for direct bank borrowings, the issuance of letters of credit totaling up to $500 million, or as support for our commercial paper program. The revolving credit facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or credit ratings. The facility agreement contains a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips or any of its consolidated subsidiaries. The amount of the facility is not subject to redetermination prior to its expiration date.

Credit facility borrowings may bear interest at a margin above the Secured Overnight Financing Rate (SOFR). The facility agreement calls for commitment fees on available, but unused, amounts. The facility agreement also contains early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

The revolving credit facility supports our ability to issue up to $5.5 billion of commercial paper. Commercial paper is generally limited to maturities of 90 days and is included in short-term debt on our consolidated balance sheet. With no commercial paper outstanding and no direct borrowings or letters of credit, we had access to $5.5 billion in available borrowing capacity under our revolving credit facility at December 31, 2025 and 2024.

For information on Finance Leases, *see Note 13.*

The current credit ratings on our long-term debt are:

- Fitch: “A” with a “stable” outlook
- S&P: “A-” with a “stable” outlook
- Moody's: “A2” with a “stable” outlook

We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity upon downgrade of our credit ratings. If our credit ratings are downgraded from their current levels, it could increase the cost of corporate debt available to us and restrict our access to the commercial paper markets. If our credit ratings were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our revolving credit facility.

At both December 31, 2025 and 2024, we had $283 million of certain variable rate demand bonds (VRDBs) outstanding with maturities ranging through 2035. The VRDBs are redeemable at the option of the bondholders on any business day. If they are ever redeemed, we have the ability and intent to refinance on a long-term basis, therefore, the VRDBs are included in the “Long-term debt” line on our consolidated balance sheet.

Note 8—Guarantees

At December 31, 2025, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability because the fair value of the obligation is immaterial. In addition, unless otherwise stated, we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

APLNG Guarantees

At December 31, 2025, we had multiple outstanding guarantees in connection with our 47.5 percent ownership interest in APLNG. The following is a description of the guarantees with values calculated utilizing December 2025 exchange rates:

- During the third quarter of 2016, we issued a guarantee to facilitate the withdrawal of our pro-rata portion of the funds in a project finance reserve account. We estimate the remaining term of this guarantee to be five years. Our maximum exposure under this guarantee is approximately $210 million and may become payable if an enforcement action is commenced by the project finance lenders against APLNG. At December 31, 2025, the carrying value of this guarantee was approximately $14 million.

- In conjunction with our original purchase of an ownership interest in APLNG from Origin Energy Limited in October 2008, we agreed to reimburse Origin Energy Limited for our share of the existing contingent liability arising under guarantees of an existing obligation of APLNG to deliver natural gas under several sales agreements. The final guarantee expires in the fourth quarter of 2041. Our maximum potential liability for future payments, or cost of volume delivery, under these guarantees is estimated to be $600 million ($1.0 billion in the event of intentional or reckless breach) and would become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG.

- We have guaranteed the performance of APLNG with regard to certain other contracts executed in connection with the project's continued development. The guarantees have remaining terms of 11 to 20 years or the life of the venture. Our maximum potential amount of future payments related to these guarantees is approximately $520 million and would become payable if APLNG does not perform. At December 31, 2025, the carrying value of these guarantees was approximately $35 million.

QatarEnergy LNG Limited Guarantees

We have guaranteed our portion of certain fiscal and other joint venture obligations as a shareholder in NFE4 and NFS3. These guarantees have an approximate 30-year term with no maximum limit. At December 31, 2025, the carrying value of these guarantees was approximately $14 million.

Equatorial Guinea Guarantees

We have guaranteed payment obligations as a shareholder in both Equatorial Guinea LNG Operations, S.A., a fully owned subsidiary of Equatorial Guinea LNG Holdings Limited, and Alba Plant LLC with regard to certain agreements to process third-party gas. These guarantees have two years remaining, and the maximum potential future payments related to these guarantees is approximately $116 million. At December 31, 2025, the carrying value of these guarantees was approximately $4 million.

Other Guarantees

We have other guarantees with maximum future potential payment amounts totaling approximately $580 million, which consist primarily of guarantees of the residual value of leased office buildings and guarantees of the residual value of corporate aircraft. These guarantees have remaining terms of one to five years and would become payable if certain asset values are lower than guaranteed amounts at the end of the lease or contract term, business conditions decline at guaranteed entities, or as a result of nonperformance of contractual terms by guaranteed parties. At December 31, 2025, there was no liability recognized for these guarantees.

Indemnifications

Over the years, we have entered into agreements to sell ownership interests in certain legal entities, joint ventures and assets that gave rise to qualifying indemnifications. These agreements include indemnifications for taxes and environmental liabilities. The carrying amount recorded for these indemnifications at December 31, 2025, was approximately $30 million. Those related to environmental issues have terms that are generally indefinite, and the maximum amounts of future payments are generally unlimited. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. *See Note 9* for additional information about environmental liabilities.

Note 9—Contingencies and Commitments

A number of lawsuits involving a variety of claims arising in the ordinary course of business have been filed against ConocoPhillips. We also may be required to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the low end of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. We accrue receivables for insurance or other third-party recoveries when applicable. With respect to income tax-related contingencies, we use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. *See Note 15*, for additional information about income tax-related contingencies.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental

We are subject to international, federal, state and local environmental laws and regulations and record accruals for environmental liabilities based on management's best estimates. These estimates are based on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies' cleanup experience, and data released by the U.S. EPA or other organizations. We consider unasserted claims in our determination of environmental liabilities, and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for other sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all cleanup costs related to any site at which we have been designated as a potentially responsible party. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the U.S. EPA or the agency concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly. As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit, and some of the indemnifications are subject to dollar limits and time limits.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and other comparable state and international sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. *See Note 6* for a summary of our accrued environmental liabilities.

Litigation and Other Contingencies

We are subject to various lawsuits and claims including but not limited to matters involving oil and gas royalty and severance tax payments, gas measurement and valuation methods, contract disputes, environmental damages, climate change, personal injury and property damage. Our primary exposures for such matters relate to alleged royalty and tax underpayments on certain federal, state and privately owned properties, claims of alleged environmental contamination and damages from historic operations, and climate change. We will continue to defend ourselves vigorously in these matters.

Our legal organization applies its knowledge, experience and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases that have been scheduled for trial and/or mediation. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2025, we had performance obligations secured by letters of credit of $331 million (issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, commercial activities and services incident to the ordinary conduct of business.

In 2007, the government of Venezuela expropriated ConocoPhillips' interests in the Petrozuata and Hamaca heavy oil ventures, as well as the offshore Corocoro development project. In response, ConocoPhillips initiated international arbitration proceedings before the ICSID. In March 2019, an ICSID tribunal unanimously ordered the government of Venezuela to pay ConocoPhillips approximately $8.7 billion (later reduced to $8.5 billion) plus interest for the unlawful expropriation of the projects. On January 22, 2025, an ICSID annulment committee dismissed Venezuela's application to annul the tribunal's decision and upheld the $8.5 billion award plus interest in full. Separate arbitrations before the ICC resulted in additional awards against Petróleos de Venezuela, S.A. (PDVSA) and three of its affiliates, including an award for approximately $2 billion plus interest, for the Petrozuata and Hamaca projects, and a $33 million award, for the Corocoro project, plus interest. Cumulatively, as of December 31, 2025, the company has received approximately $794 million in connection with the first ICC award. Collection actions for all three awards are ongoing.

ConocoPhillips has ensured that all actions related to these arbitration awards meet all appropriate U.S. regulatory requirements, including those related to any applicable sanctions imposed by the U.S. against Venezuela.

Beginning in 2017, governmental entities and individuals in several states/territories in the U.S. have filed lawsuits against oil and gas companies, including ConocoPhillips, seeking compensatory damages and equitable relief to abate alleged climate change related impacts. Additional lawsuits with similar allegations are expected to be filed. The legal and factual issues are unprecedented, therefore, there is significant uncertainty about the scope of the claims and alleged damages and any potential impact on the company's financial condition. ConocoPhillips believes these lawsuits are factually and legally meritless and are an inappropriate vehicle to address the challenges associated with climate change and will vigorously defend against such lawsuits.

Several Louisiana parishes and the State of Louisiana have filed numerous lawsuits under Louisiana's State and Local Coastal Resources Management Act (SLCRMA) against oil and gas companies, including ConocoPhillips, seeking compensatory damages for contamination and erosion of the Louisiana coastline allegedly caused by historical oil and gas operations. ConocoPhillips entities are defendants in several of the lawsuits and will vigorously defend against them. Because Plaintiffs' SLCRMA theories are unprecedented, there is uncertainty about these claims (both as to scope and damages), and we continue to evaluate our exposure in these lawsuits while assessing options for early resolution.

In October 2020, the Bureau of Safety and Environmental Enforcement (BSEE) ordered the prior owners of Outer Continental Shelf (OCS) Lease P-0166, including ConocoPhillips, to decommission the lease facilities, including two offshore platforms located near Carpinteria, California. This order was sent after the current owner of OCS Lease P-0166 relinquished the lease and abandoned the lease platforms and facilities. BSEE's order to ConocoPhillips is premised on its connection to Phillips Petroleum Company, a legacy company of ConocoPhillips, which held a historical 25 percent interest in this lease and operated these facilities but sold its interest approximately 30 years ago. ConocoPhillips continues to evaluate its exposure in this matter.

In July 2021, a federal securities class action was filed against Concho Resources Inc. (Concho), certain of Concho's officers, and ConocoPhillips as Concho's successor in the United States District Court for the Southern District of Texas. On October 21, 2021, the court issued an order appointing Utah Retirement Systems and the Construction Laborers Pension Trust for Southern California as lead plaintiffs (Lead Plaintiffs). On January 7, 2022, the Lead Plaintiffs filed their consolidated complaint alleging that Concho made materially false and misleading statements regarding its business and operations in violation of the federal securities laws and seeking unspecified damages, attorneys' fees, costs, equitable/injunctive relief and such other relief that may be deemed appropriate. The defendants filed a motion to dismiss the consolidated complaint on March 8, 2022. On June 23, 2023, the court denied defendants' motion as to most defendants including Concho/ConocoPhillips. On April 7, 2025, the court certified a class. We believe the allegations in the action are without merit and are vigorously defending this litigation.

ConocoPhillips is involved in a pending dispute with commercial counterparties relating to the propriety of its force majeure notices following Winter Storm Uri in 2021. We believe this claim is without merit and we are vigorously defending the dispute.

Long-Term Unconditional Purchase Obligations and Commitments, Including Throughput and Take-or-Pay Agreements
We have certain throughput agreements and take-or-pay agreements in support of financing arrangements. The agreements are primarily related to LNG offtake purchase commitments. The fixed and determinable portion of the remaining estimated payments under these various agreements as of December 31, 2025 is: 2026—$7 million; 2027—$7 million; 2028—$397 million; 2029—$558 million; 2030—$602 million; and 2031 and after—$23 billion. Generally, variable components of these obligations include commodity futures prices and estimated future inflation rates. Purchases of LNG under these commitments are expected to be offset in the same or approximately same periods by cash received from the related sales transactions. Total payments under these agreements were $25 million in 2025, $24 million in 2024 and $26 million in 2023.

Note 10—Derivative and Financial Instruments

We use futures, forwards, swaps and options in various markets to meet our customer needs, capture market opportunities and manage foreign exchange currency risk.

Commodity Derivative Instruments
Our commodity business primarily consists of natural gas, crude oil, bitumen, NGLs, LNG and power.

Commodity derivative instruments are held at fair value on our consolidated balance sheet. Where these balances have the right of setoff, they are presented on a net basis. Related cash flows are recorded as operating activities on our consolidated statement of cash flows. On our consolidated income statement, gains and losses are recognized either on a gross basis if directly related to our physical business or a net basis if held for trading. Gains and losses related to contracts that meet and are designated with the NPNS exception are recognized upon settlement. We generally apply this exception to eligible crude contracts and certain gas contracts. We do not apply hedge accounting for our commodity derivatives.

The following table presents the gross fair values of our commodity derivatives, excluding collateral, on our consolidated balance sheet:

	Millions of Dollars	
	2025	2024
Assets		
Prepaid expenses and other current assets	$ **491**	394
Other assets	**113**	94
Liabilities		
Other accruals	**438**	397
Other liabilities and deferred credits	**100**	83

The gains (losses) from commodity derivatives included in our consolidated income statement are presented in the following table:

	Millions of Dollars		
	2025	2024	2023
Sales and other operating revenues	$ **230**	133	86
Other income	**(8)**	(4)	(6)
Purchased commodities	**(97)**	(133)	(90)

The table below summarizes our net exposures resulting from outstanding commodity derivative contracts:

	Open Position Long/(Short)	
	2025	2024
Commodity		
Natural gas and power (BCF equivalent)		
Fixed price	**(15)**	(17)
Basis	**(17)**	—

Interest Rate Derivative Instruments

In 2023, PALNG executed interest rate swaps that had the effect of converting 60 percent of the projected term loans outstanding to finance the cost of development and construction of Phase 1 from floating- to fixed-rate. In 2024, PALNG dedesignated a portion of the interest rate swaps as a cash flow hedge and the remaining portion was dedesignated during the first quarter of 2025. Changes in the fair value of the dedesignated hedging instruments are reported in the "Equity in earnings of affiliates" line on our consolidated income statement.

For the years ended December 31, 2025 and 2024, we recognized gains of $18 million and $35 million, respectively, in "Equity in earnings of affiliates" related to these swaps. For the year ended December 31, 2025, unrealized gains/losses recognized in other comprehensive income (loss) related to these swaps was nil. For the years ended December 31, 2024 and 2023, we recognized an unrealized loss of $56 million and an unrealized gain of $78 million, respectively, in other comprehensive income (loss) related to these swaps.

Financial Instruments

We invest in financial instruments with maturities based on our cash forecasts for the various accounts and currency pools we manage. The types of financial instruments in which we currently invest include:

- Time deposits: Interest bearing deposits placed with financial institutions for a predetermined amount of time.
- Demand deposits: Interest bearing deposits placed with financial institutions. Deposited funds can be withdrawn without notice.
- Commercial paper: Unsecured promissory notes issued by a corporation, commercial bank or government agency purchased at a discount to mature at par.
- U.S. government or government agency obligations: Securities issued by the U.S. government or U.S. government agencies.
- Foreign government obligations: Securities issued by foreign governments.
- Corporate bonds: Unsecured debt securities issued by corporations.
- Asset-backed securities: Collateralized debt securities.

The following investments are carried on our consolidated balance sheet at cost, plus accrued interest and the table reflects remaining maturities at December 31, 2025 and 2024:

	Millions of Dollars			
	Carrying Amount			
	Cash and cash equivalents		Short-term investments	
	2025	2024	**2025**	2024
Cash	**$ 543**	770		
Demand Deposits	**3,781**	3,211		
Time Deposits				
1 to 90 days	**975**	1,364	**6**	1
91 to 180 days			**17**	5
Within one year			**8**	6
U.S. Government Obligations				
1 to 90 days	**1,198**	260	**—**	—
	$ 6,497	5,605	**31**	12

The following investments in debt securities classified as available for sale are carried at fair value on our consolidated balance sheet at December 31, 2025 and 2024:

	Millions of Dollars					
	Carrying Amount					
	Cash and cash equivalents		Short-term investments		Investments and long-term receivables	
	2025	2024	**2025**	2024	**2025**	2024
Major Security Type						
Corporate Bonds	**$ —**	—	**308**	338	**651**	612
Commercial Paper	**—**	2	**72**	77		
U.S. Government Obligations	**—**	—	**46**	43	**224**	218
U.S. Government Agency Obligations			**—**	—	**1**	7
Foreign Government Obligations			**9**	4	**9**	12
Asset-backed Securities			**18**	33	**263**	205
	$ —	2	**453**	495	**1,148**	1,054

Cash and cash equivalents and short-term investments have remaining maturities within one year. Investments and long-term receivables have remaining maturities that vary from greater than one year through 13 years.

The following table summarizes the amortized cost basis and fair value of investments in debt securities classified as available for sale at December 31:

	Millions of Dollars			
	Amortized Cost Basis		Fair Value	
	2025	2024	**2025**	2024
Major Security Type				
Corporate Bonds	$ **953**	947	**959**	950
Commercial Paper	**72**	79	**72**	79
U.S. Government Obligations	**268**	262	**270**	261
U.S. Government Agency Obligations	**1**	7	**1**	7
Foreign Government Obligations	**18**	16	**18**	16
Asset-backed Securities	**280**	237	**281**	238
	$ **1,592**	1,548	**1,601**	1,551

No allowance for credit losses has been recorded on investments in debt securities which are in an unrealized loss position.

For the years ended December 31, 2025 and 2024, proceeds from sales and redemptions of investments in debt securities classified as available for sale were $962 million and $868 million, respectively. Gross realized gains and losses included in earnings from those sales and redemptions were negligible. The cost of securities sold and redeemed is determined using the specific identification method.

Credit Risk
Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, short-term investments, long-term investments in debt securities, OTC derivative contracts and trade receivables. Our cash equivalents and short-term investments could be placed in high-quality commercial paper, government money market funds, U.S. government and government agency obligations, time deposits with major international banks and financial institutions, high-quality corporate bonds, foreign government obligations and asset-backed securities. Our long-term investments in debt securities are placed in high-quality corporate bonds, asset-backed securities, U.S. government and government agency obligations and foreign government obligations.

The credit risk from our OTC derivative contracts, such as forwards, swaps and options, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared primarily with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We may require collateral to limit the exposure to loss, including letters of credit, prepayments and surety bonds, as well as master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due to us.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral, such as transactions administered through the New York Mercantile Exchange.

The aggregate fair value of all derivative instruments with such credit risk-related contingent features that were in a liability position at December 31, 2025 and 2024, was $73 million and $70 million, respectively. For these instruments, no collateral was posted at December 31, 2025 and 2024. If our credit rating had been downgraded below investment grade at December 31, 2025, we would have been required to post $32 million of additional collateral, either with cash or letters of credit.

Note 11—Fair Value Measurement

We carry a portion of our assets and liabilities at fair value that are measured at the reporting date using an exit price (i.e., the price that would be received to sell an asset or paid to transfer a liability) and disclosed according to the quality of valuation inputs under the fair value hierarchy.

The classification of an asset or liability is based on the lowest level of input significant to its fair value. Those that are initially classified as Level 3 are subsequently reported as Level 2 when the fair value derived from unobservable inputs is inconsequential to the overall fair value, or if corroborated market data becomes available. Assets and liabilities initially reported as Level 2 are subsequently reported as Level 3 if corroborated market data is no longer available. There were no material transfers into or out of Level 3 during 2025 or 2024.

Recurring Fair Value Measurement

Financial assets and liabilities reported at fair value on a recurring basis include our investments in debt securities classified as available for sale, commodity derivatives, and our contingent consideration arrangement related to the Surmont acquisition. *See Note 3*.

- Level 1 derivative assets and liabilities primarily represent exchange-traded futures and options that are valued using unadjusted prices available from the underlying exchange. Level 1 financial assets also include our investments in U.S. government obligations classified as available for sale debt securities, which are valued using exchange prices.
- Level 2 derivative assets and liabilities primarily represent OTC swaps, options and forward purchase and sale contracts that are valued using adjusted exchange prices, prices provided by brokers or pricing service companies that are all corroborated by market data. Level 2 financial assets also include our investments in debt securities classified as available for sale including investments in corporate bonds, commercial paper, asset-backed securities, U.S. government agency obligations and foreign government obligations that are valued using pricing provided by brokers or pricing service companies that are corroborated with market data.
- Level 3 derivative assets and liabilities consist of OTC swaps, options and forward purchase and sale contracts where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived value uses industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in management's best estimate of fair value. Level 3 commodity derivative activity was not material for all periods presented.
- Level 3 liabilities include the fair value of future quarterly contingent payments associated with the Surmont acquisition. In October 2023, we completed our acquisition of the remaining 50 percent working interest in Surmont, an asset in our Canada segment, from TotalEnergies EP Canada Ltd. The consideration for the acquisition included a contingent consideration arrangement requiring payment of up to $0.4 billion CAD over a five-year term. The contingent payments represent $2 million for every dollar that WCS pricing exceeds $52 per barrel during the month, subject to certain production targets being achieved. The undiscounted amount we could pay under this arrangement was up to $0.3 billion USD at closing.

The following table summarizes the fair value hierarchy for gross financial assets and liabilities (i.e., unadjusted where the right of setoff exists for commodity derivatives accounted for at fair value on a recurring basis):

	Millions of Dollars							
	December 31, 2025				December 31, 2024			
	Level 1	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Assets								
Investments in debt securities	**$ 270**	**1,331**	**—**	**1,601**	261	1,290	—	1,551
Commodity derivatives	**306**	**230**	**68**	**604**	201	252	35	488
Total assets	**$ 576**	**1,561**	**68**	**2,205**	462	1,542	35	2,039
Liabilities								
Commodity derivatives	**$ 354**	**124**	**60**	**538**	275	160	45	480
Contingent consideration	**—**	**—**	**—**	**—**	—	—	145	145
Total liabilities	**$ 354**	**124**	**60**	**538**	275	160	190	625

For the year ended December 31, 2025, we have made payments of $80 million, and $237 million in total under the contingent consideration arrangement since the date of the Surmont acquisition, included in the "Other" line within the financing activities section of our consolidated statement of cash flows. As of December 31, 2025, the fair value of the contingent consideration liability was zero due to the commodity price outlook over the remaining term. The range and arithmetic average of the significant unobservable input used in the Level 3 fair value measurement was as follows:

	Fair Value (Millions of Dollars)	Valuation Technique	Unobservable Input	Range (Arithmetic Average)
Contingent Consideration - Surmont as of:				
December 31, 2025	$ —	Discounted cash flow	Commodity price outlook* ($/BOE)	$43.17 - $51.97 ($46.47)
December 31, 2024	145			$48.63 - $57.53 ($53.38)

**Commodity price outlook based on a combination of external pricing service companies' outlooks and internal outlook.*

The following table summarizes those commodity derivative balances subject to the right of setoff as presented on our consolidated balance sheet. We have elected to offset the recognized fair value amounts for multiple derivative instruments executed with the same counterparty in our financial statements when a legal right of setoff exists.

	Millions of Dollars						
			Amounts Subject to Right of Setoff				
	Gross Amounts Recognized	Amounts Not Subject to Right of Setoff	Gross Amounts	Gross Amounts Offset	Net Amounts Presented	Cash Collateral	Net Amounts
December 31, 2025							
Assets	**$ 604**	**2**	**602**	**361**	**241**	**6**	**235**
Liabilities	**538**	**1**	**537**	**361**	**176**	**53**	**123**
December 31, 2024							
Assets	$ 488	—	488	278	210	—	210
Liabilities	480	—	480	278	202	73	129

At December 31, 2025 and 2024, we did not present any amounts gross on our consolidated balance sheet where we had the right of setoff.

Reported Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents and short-term investments: The carrying amount reported on the balance sheet approximates fair value. For those investments classified as available for sale debt securities, the carrying amount reported on the balance sheet is fair value.
- Accounts and notes receivable (including long-term and related parties): The carrying amount reported on the balance sheet approximates fair value.
- Investments in debt securities classified as available for sale: The fair value of investments in debt securities categorized as Level 1 in the fair value hierarchy is measured using exchange prices. The fair value of investments in debt securities categorized as Level 2 in the fair value hierarchy is measured using pricing provided by brokers or pricing service companies that are corroborated with market data. *See Note 10*.
- Accounts payable (including related parties) and floating-rate debt: The carrying amount of accounts payable and floating-rate debt reported on the balance sheet approximates fair value.
- Fixed-rate debt: The estimated fair value of fixed-rate debt is measured using prices available from a pricing service that is corroborated by market data; therefore, these liabilities are categorized as Level 2 in the fair value hierarchy.
- Commercial paper: The carrying amount of our commercial paper instruments approximates fair value and is reported on the balance sheet as short-term debt.

The following table summarizes the net fair value of financial instruments (i.e., adjusted where the right of setoff exists for commodity derivatives):

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2025	2024	**2025**	2024
Financial assets				
Commodity derivatives	**237**	210	**237**	210
Investments in debt securities	**1,601**	1,551	**1,601**	1,551
Financial liabilities				
Total debt, excluding finance leases	**22,643**	23,384	**22,698**	22,997
Commodity derivatives	**124**	129	**124**	129

Note 12—Equity

Common Stock

The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

	Shares		
	2025	2024	2023
Issued			
Beginning of year	**2,250,672,734**	2,103,772,516	2,100,885,134
Acquisition of Marathon Oil	**—**	142,941,624	—
Distributed under benefit plans	**2,845,548**	3,958,594	2,887,382
End of year	**2,253,518,282**	2,250,672,734	2,103,772,516
Held in Treasury			
Beginning of year	**974,806,010**	925,670,961	877,029,062
Repurchase of common stock	**53,544,176**	49,135,049	48,641,899
End of year	**1,028,350,186**	974,806,010	925,670,961

Preferred Stock

We have authorized 500 million shares of preferred stock, par value $0.01 per share, none of which was issued or outstanding at December 31, 2025 or 2024.

Repurchase of Common Stock

In late 2016, we initiated our current share repurchase program. In October 2024, our Board of Directors approved an increase from our prior authorization of $45 billion by a total of the lesser of $20 billion or the number of shares issued in our acquisition of Marathon Oil, such that the company is not to exceed $65 billion in aggregate purchases. Since inception of our current program, shares repurchased totaled 486 million shares at a cost of $39.3 billion through the end of December 2025.

Note 13—Non-Mineral Leases

The company primarily leases office buildings and drilling equipment, as well as ocean transport vessels, tugboats, corporate aircraft, and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, and other leases include payment provisions that vary based on the nature of usage of the leased asset. Additionally, the company has executed certain leases that provide it with the option to extend or renew the term of the lease, terminate the lease prior to the end of the lease term, or purchase the leased asset as of the end of the lease term. In other cases, the company has executed lease agreements that require it to guarantee the residual value of certain leased office buildings. For additional information about guarantees, *see Note 8.* For those leasing arrangements where the underlying asset is not yet constructed, the company does not control the asset during construction. There are no significant restrictions imposed on us by the lease agreements with regard to dividends, asset dispositions or borrowing ability.

We determine if an arrangement is or contains a lease at contract inception. Certain contractual arrangements may contain both lease and non-lease components. Only the lease components of these contractual arrangements are subject to the provisions of ASC Topic 842, "Leases," and any non-lease components are subject to other applicable accounting guidance; however, we have elected to adopt the optional practical expedient not to separate lease components apart from non-lease components for existing asset classes, except for crude oil and LNG Vessels. For contractual arrangements involving a new leased asset class, we determine at contract inception whether it will apply the optional practical expedient to the new leased asset class.

Leases are evaluated for classification as operating or finance leases at the commencement date of the lease and right-of-use assets and corresponding liabilities are recognized on our consolidated balance sheet based on the present value of future lease payments relating to the use of the underlying asset during the lease term. Future lease payments include variable lease payments that depend upon an index or rate using the index or rate at the commencement date and probable amounts owed under residual value guarantees. The amount of future lease payments may be increased to include additional payments related to lease extension, termination, and/or purchase options when the company has determined, at or subsequent to lease commencement, generally due to limited asset availability or operating commitments, it is reasonably certain of exercising such options. We use our incremental borrowing rate as the discount rate in determining the present value of future lease payments, unless the interest rate implicit in the lease arrangement is readily determinable. Lease payments that vary subsequent to the commencement date based on future usage levels, the nature of leased asset activities, or certain other contingencies are not included in the measurement of lease right-of-use assets and corresponding liabilities. We have elected not to record assets and liabilities on our consolidated balance sheet for lease arrangements with terms of 12 months or less.

We often enter into leasing arrangements acting in the capacity as operator for and/or on behalf of certain oil and gas joint ventures of undivided interests. If the lease arrangement can be legally enforced only against us as operator and there is no separate arrangement to sublease the underlying leased asset to our coventurers, we recognize at lease commencement a right-of-use asset and corresponding lease liability on our consolidated balance sheet on a gross basis. While we record lease costs on a gross basis in our consolidated income statement and statement of cash flows, such costs are offset by the reimbursement we receive from our coventurers for their share of the lease cost as the underlying leased asset is utilized in joint venture activities. As a result, lease cost is presented in our consolidated income statement and statement of cash flows on a proportional basis. If we are a nonoperating coventurer, we recognize a right-of-use asset and corresponding lease liability only if we were a specified contractual party to the lease arrangement and the arrangement could be legally enforced against us. In this circumstance, we would recognize both the right-of-use asset and corresponding lease liability on our consolidated balance sheet on a proportional basis consistent with our undivided interest ownership in the related joint venture.

The company has historically recorded finance lease assets and liabilities associated with certain oil and gas joint ventures on a proportional basis pursuant to accounting guidance applicable prior to the adoption date of ASC Topic 842. In accordance with the transition provisions of ASC Topic 842, and since we have elected to adopt the package of optional transition-related practical expedients, the historical accounting treatment for these leases has been carried forward and is subject to reconsideration upon the modification or other required reassessment of the arrangements prior to lease term expiration.

The following table summarizes the right-of-use assets and lease liabilities for both the operating and finance leases on our consolidated balance sheet as of December 31:

		Millions of Dollars			
		2025		2024	
		Operating Leases	Finance Leases	Operating Leases	Finance Leases
Right-of-Use Assets					
Properties, plants and equipment					
Gross			**2,007**		1,983
Accumulated DD&A			**(1,507)**		(1,336)
Net PP&E*			**500**		647
Other assets		**950**		1,017	
Lease Liabilities					
Short-term debt**			**306**		292
Other accruals		**383**		329	
Long-term debt***			**495**		648
Other liabilities and deferred credits		**567**		695	
Total lease liabilities	$	**950**	**801**	1,024	940

** Includes proportionately consolidated finance lease assets of $83 million at December 31, 2025 and $107 million at December 31, 2024.*
*** Includes proportionately consolidated finance lease liabilities of $188 million at December 31, 2025 and $181 million at December 31, 2024.*
**** Includes proportionately consolidated finance lease liabilities of $192 million at December 31, 2025 and $259 million at December 31, 2024.*

The following table summarizes our lease costs:

		Millions of Dollars		
		2025	2024	2023
Lease Cost*				
Operating lease cost	$	**447**	325	229
Finance lease cost				
Amortization of right-of-use assets		**171**	173	180
Interest on lease liabilities		**24**	29	35
Short-term lease cost**		**65**	49	40
Total lease cost***	$	**707**	576	484

** The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers.*
*** Short-term leases are not recorded on our consolidated balance sheet.*
**** Variable lease cost and sublease income are immaterial for the periods presented and therefore are not included in the table above.*

The following table summarizes the lease terms and discount rates as of December 31:

Lease Term and Discount Rate	**2025**	2024
Weighted-average term (years)		
Operating leases	**4.06**	4.41
Finance leases	**4.18**	4.86
Weighted-average discount rate (percent)		
Operating leases	**4.58**	4.62
Finance leases	**3.47**	3.40

The following table summarizes other lease information:

		Millions of Dollars	
	2025	2024	2023
Other Information*			
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from operating leases	$ **385**	248	173
Operating cash flows from finance leases	**24**	29	33
Financing cash flows from finance leases	**175**	172	169
Right-of-use assets obtained in exchange for operating lease liabilities	$ **320**	628	355
Right-of-use assets obtained in exchange for finance lease liabilities	**25**	—	9

**The amounts presented in the table above have not been adjusted to reflect amounts recovered or reimbursed from oil and gas coventurers. In addition, pursuant to other applicable accounting guidance, lease payments made in connection with preparing another asset for its intended use are reported in the "Cash flows from investing activities" section of our consolidated statement of cash flows.*

The following table summarizes future lease payments for operating and finance leases at December 31, 2025:

	Millions of Dollars	
	Operating Leases	Finance Leases
Maturity of Lease Liabilities		
2026	$ 417	363
2027	219	164
2028	143	181
2029	102	91
2030	55	57
Remaining years	109	48
Total	1,045	904
Less: portion representing imputed interest	(95)	(103)
Total lease liabilities	$ 950	801

As of December 31, 2025 and December 31, 2024, the company had approximately $1 billion and nil in future undiscounted cash flows for leases not yet commenced related to time-chartered LNG vessels in support of future LNG offtake, respectively.

Note 14—Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2025		2024		**2025**	2024
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 1,806**	**2,591**	1,525	2,866	**145**	107
Service cost	**58**	**34**	49	38	**2**	1
Interest cost	**93**	**130**	76	114	**8**	5
Plan participant contributions	**—**	**—**	—	—	**14**	12
Plan amendments	**—**	**—**	—	57	**(2)**	—
Business combinations			237			42
Actuarial (gain) loss	**89**	**(59)**	(4)	(202)	**(3)**	5
Benefits paid	**(204)**	**(142)**	(98)	(134)	**(39)**	(27)
Curtailment	**3**	**(8)**	8	—	**1**	—
Recognition of termination benefits	**—**	**—**	13	—	**—**	—
Foreign currency exchange rate change	**—**	**243**	—	(148)	**—**	—
Benefit obligation at December 31*	**$ 1,845**	**2,789**	1,806	2,591	**126**	145
**Accumulated benefit obligation portion of above at December 31:*	***$ 1,767***	***2,577***	*1,703*	*2,392*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 1,556**	**2,907**	1,306	3,085	**—**	—
Actual return on plan assets	**166**	**192**	66	18	**—**	—
Company contributions	**148**	**50**	83	88	**25**	15
Plan participant contributions	**—**	**—**	—	—	**14**	12
Business combinations			199			
Benefits paid	**(204)**	**(142)**	(98)	(134)	**(39)**	(27)
Foreign currency exchange rate change	**—**	**277**	—	(150)	**—**	—
Fair value of plan assets at December 31	**$ 1,666**	**3,284**	1,556	2,907	**—**	—
Funded Status	**$ (179)**	**495**	(250)	316	**(126)**	(145)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2025		2024		**2025**	2024
	U.S.	**Int'l.**	U.S.	Int'l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	**$ 29**	**744**	1	553	**—**	—
Current liabilities	**(81)**	**(10)**	(28)	(10)	**(24)**	(26)
Noncurrent liabilities	**(127)**	**(239)**	(223)	(227)	**(102)**	(119)
Total recognized	**$ (179)**	**495**	(250)	316	**(126)**	(145)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**5.25 %**	**4.95**	5.70	4.90	**5.60**	5.60
Rate of compensation increase	**4.50**	**4.05**	5.00	4.05		
Interest crediting rate for applicable benefits	**4.75**		4.30			
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**5.70 %**	**4.90**	5.35	4.10	**4.25**	5.35
Expected return on plan assets	**5.30**	**6.20**	5.30	5.40		
Rate of compensation increase	**5.00**	**4.10**	5.00	3.65		
Interest crediting rate for applicable benefits	**4.35**		4.20			

For both U.S. and international pension plans, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

During 2025, the actuarial losses related to the benefit obligations for U.S. plans were primarily related to a decrease in the discount rate and an increase in compensation and benefits. In addition, international plans recognized actuarial gains due to higher discount rates and lower inflation rate assumptions. During 2024, the actuarial gains related to the benefit obligations for international plans were primarily related to an increase in the discount rates.

The following tables summarize information related to the company's pension plans with projected and accumulated benefit obligations in excess of the fair value of the plans' assets:

		Millions of Dollars			
		Pension Benefits			
		2025		2024	
		U.S.	**Int'l.**	U.S.	Int'l.
Pension Plans with Projected Benefit Obligation in Excess of Plan Assets					
Projected benefit obligation	$	**208**	**258**	450	242
Fair value of plan assets		**—**	**9**	199	6
Pension Plans with Accumulated Benefit Obligation in Excess of Plan Assets					
Accumulated benefit obligation	$	**190**	**223**	425	210
Fair value of plan assets		**—**	**9**	199	6

Included in accumulated other comprehensive income (loss) at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2025		2024		**2025**	2024
		U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial loss (gain)	$	**92**	**364**	112	445	**—**	2
Unrecognized prior service cost (credit)		**—**	**61**	—	58	**1**	(21)

		Millions of Dollars					
		Pension Benefits				Other Benefits	
		2025		2024		**2025**	2024
		U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income (Loss)							
Net gain (loss) arising during the period	$	**5**	**34**	3	83	**3**	(5)
Amortization of actuarial (gain) loss included in income (loss)*		**15**	**47**	8	57	**(1)**	—
Net change during the period	$	**20**	**81**	11	140	**2**	(5)
Prior service credit (cost) arising during the period	$	**—**	**2**	—	(57)	**2**	—
Amortization of prior service cost (credit) included in income (loss)		**—**	**3**	—	—	**(24)**	(38)
Net change during the period	$	**—**	**5**	—	(57)	**(22)**	(38)

**Includes settlement (gains) losses recognized in 2025 and 2024.*

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2025		2024		2023		**2025**	2024	2023
	U.S.	**Int’l.**	U.S.	Int’l.	U.S.	Int’l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 58**	**34**	49	38	51	38	**2**	1	1
Interest cost	**93**	**130**	76	114	77	113	**8**	5	5
Expected return on plan assets	**(77)**	**(189)**	(66)	(163)	(58)	(148)	**—**	—	—
Amortization of prior service credit	**—**	**3**	—	—	—	—	**(24)**	(38)	(38)
Recognized net actuarial loss (gain)	**10**	**47**	8	58	12	67	**—**	—	(3)
Settlements loss (gain)	**5**	**—**	—	(1)	6	—	**—**	—	—
Curtailment loss (gain)	**8**	**(3)**	8	—	—	—	**1**	—	—
Net periodic benefit cost	**$ 97**	**22**	75	46	88	70	**(13)**	(32)	(35)

The components of net periodic benefit cost, other than the service cost component, are included in the “Other expenses” line item on our consolidated income statement.

We recognized a pension settlement loss of $5 million in 2025, a gain of $1 million in 2024, and a loss of $6 million in 2023 as lump-sum benefit payments from certain U.S. and international pension plans exceeded the sum of service and interest costs for those plans and led to recognition of settlement gains or losses.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net actuarial gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple non-pension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, most with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the U.S. pre-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 6.50 percent in 2026 that declines to 5 percent by 2032. The measurement of the U.S. post-65 retiree medical accumulated postretirement benefit obligation assumes a health care cost trend rate of 4.7 percent in 2026 that increases to 5 percent by 2030.

Plan Assets

We follow a policy of broadly diversifying pension plan assets across asset classes and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. The target allocations for plan assets, aggregated across U.S. and international plans, are 28 percent in equity securities, 68 percent in debt securities and 4 percent in real estate. Generally, the plan investments are publicly traded; therefore, minimizing liquidity risk in the portfolio.

The following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2025 and 2024.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices in active markets for identical assets and liabilities.
- Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and quoted market prices for similar assets and liabilities in active markets and for identical assets and liabilities in markets that are not active. If there have been no market transactions in a particular fixed income security, its fair value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable quoted market prices are not available, fair value is based on pricing models that use something other than actual

market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.
- Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.
- Fair values of mutual funds are based on quoted market prices, which represent the net asset value of shares held.
- Time deposits are valued at cost, which approximates fair value.
- Cash is valued at cost, which approximates fair value. Fair values of international cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates. U.S. cash balances held in the form of short-term fund units that are redeemable at the measurement date are categorized as Level 2.
- Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.
- Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the plans' participants.
- Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.
- A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract, which is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. The participating interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of quoted market prices, recently executed transactions and an actuarial present value computation for contract obligations. At December 31, 2025, the participating interest in the annuity contract was valued at $40 million and consisted of $107 million in debt securities, less $67 million for the accumulated benefit obligation covered by the contract. At December 31, 2024, the participating interest in the annuity contract was valued at $42 million and consisted of $113 million in debt securities, less $71 million for the accumulated benefit obligation covered by the contract. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

The fair values of our pension plan assets at December 31, by asset class were as follows:

	Millions of Dollars								
	U.S.				International				
		Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2025									
Equity securities									
International		**1**	**—**	**—**	**1**	**1**	**—**	**—**	**1**
Mutual funds		**20**	**—**	**—**	**20**	**514**	**103**	**—**	**617**
Debt securities									
Corporate		**—**	**—**	**1**	**1**	**—**	**—**	**—**	**—**
Mutual funds		**—**	**—**	**—**	**—**	**572**	**—**	**—**	**572**
Private equity funds				**2**	**2**				
Cash and cash equivalents		**1**	**—**	**—**	**1**	**18**	**—**	**—**	**18**
Insurance contracts				**4**	**4**				
Real estate		**—**	**—**	**2**	**2**	**—**	**—**	**169**	**169**
Total in fair value hierarchy	**$**	**22**	**—**	**9**	**31**	**1,105**	**103**	**169**	**1,377**
Investments measured at net asset value*									
Equity securities									
Common/collective trusts					**353**				**325**
Debt securities									
Common/collective trusts					**1,213**				**1,579**
Cash and cash equivalents					**9**				**—**
Real estate					**21**				**—**
Total**	**$**	**22**	**—**	**9**	**1,627**	**1,105**	**103**	**169**	**3,281**

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*

***Excludes the participating interest in the insurance annuity contract with a net asset of $40 million and net receivables related to security transactions of $2 million.*

The fair values of our pension plan assets at December 31, by asset class were as follows:

	Millions of Dollars							
	U.S.				International			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2024								
Equity securities								
U.S.	$ 5	—	—	5	—	—	—	—
International	38	—	—	38	—	—	—	—
Mutual funds	17	—	—	17	445	77	—	522
Debt securities								
Corporate	—	1	—	1	—	—	—	—
Mutual funds	—	—	—	—	451	—	—	451
Private equity funds			3	3				
Cash and cash equivalents	—	—	—	—	25	—	—	25
Insurance contracts			4	4				
Real estate	—	—	3	3	—	—	136	136
Total in fair value hierarchy	$ 60	1	10	71	921	77	136	1,134
Investments measured at net asset value*								
Equity securities								
Common/collective trusts				479				194
Debt securities								
Common/collective trusts				938				1,575
Cash and cash equivalents				3				—
Real estate				22				—
Total**	$ 60	1	10	1,513	921	77	136	2,903

**In accordance with FASB ASC Topic 715, "Compensation—Retirement Benefits," certain investments that are to be measured at fair value using the net asset value per share (or its equivalent) practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Change in Fair Value of Plan Assets.*
***Excludes the participating interest in the insurance annuity contract with a net asset of $42 million and net receivables related to security transactions of $5 million.*

Level 3 activity was not material for all periods presented.

Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2026, we expect to contribute approximately $160 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $60 million to our international qualified and nonqualified pension and postretirement benefit plans.

The following benefit payments, which are exclusive of amounts to be paid from the insurance annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

	Millions of Dollars			
	Pension Benefits			Other Benefits
		U.S.	Int'l.	
2026	$	511	135	17
2027		279	139	17
2028		164	142	16
2029		161	146	14
2030		151	151	13
2031–2035		628	799	52

Restructuring Costs

During 2025, we announced certain restructuring initiatives and reduced our overall employee workforce, resulting in associated severance expense of $286 million, with $214 million reported as "Production and operating expenses" and $72 million reported as "Selling, general and administrative expenses" on the consolidated income statement. Approximately $43 million was in Alaska, $87 million in Lower 48, $29 million in Canada, $48 million in Europe, Middle East and North Africa, $7 million in Asia Pacific and $72 million in Corporate and Other.

In 2024, accruals included severance costs associated with contractual termination benefits applicable to officers and employees of Marathon Oil as of the acquisition date. *See Note 3.*

The following table summarizes our severance accrual activity:

	Millions of Dollars			
		2025	2024	2023
Balance at January 1	**$**	**331**	12	31
Accruals*		**365**	328	1
Benefit payments		**(320)**	(9)	(20)
Foreign currency translation adjustment		**2**	—	—
Balance at December 31**	**$**	**378**	331	12

**Partner recoveries of $73 million are accrued as receivables as of December 31, 2025. The expenses in our consolidated income statement are presented net of this amount.*

***Of the remaining balance at December 31, 2025, $300 million is classified as short-term.*

Defined Contribution Plans

Most U.S. employees are eligible to participate in a defined contribution plan. Company contributions can vary based on employee compensation and contribution elections, whether the employee is accruing benefits in a defined benefit plan and company discretion. Company contributions charged to expense for U.S. defined contribution plans were $160 million in 2025, $152 million in 2024 and $151 million in 2023.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $27 million in 2025, $25 million in 2024 and $23 million in 2023.

Share-Based Compensation Plans

The 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (Omnibus Plan) was approved by shareholders in May 2023, replacing similar prior plans and providing that no new awards shall be granted under the prior plans. Over its 10-year life, the Omnibus Plan allows the issuance of up to 36 million shares of our common stock for compensation to our employees and directors, but the available shares (i) are reduced by awards granted under the prior plan between the board adoption date (February 15, 2023) and the shareholder approval date (May 16, 2023) and (ii) are increased by any shares of common stock represented by awards granted under the Omnibus Plan or the prior plans that are forfeited, expire or are cancelled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company, excluding shares surrendered in payment of the exercise of a stock option or stock appreciation right, shares not issued in connection with the stock settlement of a stock appreciation right, or shares reacquired by the company using cash proceeds from the exercise of a stock option. The Human Resources and Compensation Committee of our Board of Directors is authorized to determine the types, terms, conditions and limitations of awards granted. Awards may be granted in the form of, but not limited to, stock options, RSUs and performance share units (PSU) to employees and non-employee directors who contribute to the company's continued success and profitability.

Total share-based compensation expense is measured using the grant date fair value for our equity-classified awards and the settlement date fair value for our liability-classified awards. We recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or, for awards that provide for retirement-based vesting, the period beginning at the start of the service period and ending upon the date when an employee first becomes eligible for retirement vesting under award terms. Other than certain retention awards, our share-based compensation programs generally provide accelerated vesting in whole or in part (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). We recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Compensation Expense—Total share-based compensation expense recognized in net income (loss) and the associated tax benefit were:

	Millions of Dollars			
		2025	2024	2023
Compensation cost	$	**336**	268	334
Tax benefit		**79**	67	84

Stock Options—Stock options granted under the provisions of the Omnibus Plan and prior plans permit purchase of our common stock at exercise prices equivalent to the average fair market value of ConocoPhillips common stock on the date the options were granted. The options have terms of 10 years and generally vest ratably on the first, second and third anniversaries of the date of grant. Options awarded to certain employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period. Beginning in 2018, stock option grants were discontinued.

The following summarizes our stock option activity for the year ended December 31, 2025:

					Millions of Dollars
	Options		Weighted-Average Exercise Price		Aggregate Intrinsic Value
Outstanding at December 31, 2024	2,051,075	$	43.16	$	113
Exercised	**(1,086,350)**		**38.71**		**60**
Outstanding at December 31, 2025	**964,725**	**$**	**48.17**	**$**	**44**
Vested at December 31, 2025	**964,725**	**$**	**48.17**	**$**	**44**
Exercisable at December 31, 2025	**964,725**	**$**	**48.17**	**$**	**44**

The weighted-average remaining contractual term of outstanding options, vested options and exercisable options at December 31, 2025, were all 1.03 years. The aggregate intrinsic value of options exercised was $63 million in 2024 and $58 million in 2023.

During 2025, we received $15 million in cash and $27 million in cashless exercises and realized a tax benefit of $13 million from the exercise of options. At December 31, 2025, all outstanding stock options were fully vested with no remaining compensation cost to be recorded.

Stock Unit Programs—RSUs granted annually under the provisions of the Omnibus Plan and the general and executive RSU programs vest in one installment on the third anniversary of the grant date. RSUs granted under the Omnibus Plan for a variable long-term incentive retention program vest ratably on the first, second and third anniversaries of the grant date. RSUs are also granted ad hoc to attract or retain key personnel, or assumed as a result of an acquisition, and the terms and conditions under which these RSUs vest vary by award.

Stock-Settled

Upon vesting, these RSUs are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to retirement eligible employees under the general and executive RSU programs may vest earlier; however, those units are not settled through the issuance of common stock until after the earlier of separation from the company or the end of the regularly scheduled vesting period. Until issued as stock, most recipients of the RSUs receive a cash payment of a dividend equivalent or an accrued reinvested dividend equivalent that is charged to retained earnings. The grant date fair market value of these RSUs is deemed equal to the average ConocoPhillips stock price on the grant date. The grant date fair market value of RSUs that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the estimated dividends that will not be received.

The following summarizes our stock-settled RSU activity for the year ended December 31, 2025:

	Stock Units	Weighted-Average Grant Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2024	6,471,773	$ 104.89	
Granted	**2,998,555**	**99.26**	
Forfeited	**(274,989)**	**103.37**	
Issued	**(2,938,338)**	**98.14**	**$ 285**
Outstanding at December 31, 2025	**6,257,001**	**$ 105.43**	
Not Vested at December 31, 2025	**4,300,663**	**$ 105.25**	

At December 31, 2025, the remaining unrecognized compensation cost from the unvested stock-settled RSUs was $188 million, which will be recognized over a weighted-average period of 1.71 years, the longest period being 3.42 years. The weighted-average grant date fair value of stock-settled RSUs granted during 2024 and 2023 was $109.79 and $110.91, respectively. The total fair value of stock-settled RSUs issued during 2024 and 2023 was $410 million and $284 million, respectively.

Performance Share Program—Under the Omnibus Plan, we also annually grant restricted PSUs to senior management. These PSUs are authorized three years prior to their effective grant date (the performance period). Compensation expense is initially measured using the average fair market value of ConocoPhillips common stock and is subsequently adjusted, based on changes in the ConocoPhillips stock price through the end of each subsequent reporting period, through the grant date for stock-settled awards and the settlement date for cash-settled awards.

Stock-Settled
Stock-settled PSUs are settled by issuing one share of ConocoPhillips common stock per unit. For performance periods beginning before 2009, PSUs do not vest until the employee becomes eligible for retirement by reaching age 55 with five years of service, and restrictions do not lapse until the employee separates from the company. With respect to awards for performance periods beginning in 2009 through 2012, PSUs do not vest until the earlier of the date the employee becomes eligible for retirement by reaching age 55 with five years of service or five years after the grant date of the award, and restrictions do not lapse until the earlier of the employee's separation from the company or five years after the grant date (although recipients can elect to defer the lapsing of restrictions until separation). We recognize compensation expense for these awards beginning on the grant date and ending on the date the PSUs are scheduled to vest. Because these awards are authorized three years prior to the effective grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Until issued as stock, recipients of the stock-settled PSUs issued prior to 2013 receive a cash payment of a dividend equivalent that is charged to retained earnings. Beginning in 2013, stock-settled PSUs authorized for future grants vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending on the conclusion of the performance period. Until issued as stock, recipients of these PSUs receive an accrued reinvested dividend equivalent that is charged to compensation expense.

The following summarizes our stock-settled Performance Share Program activity for the year ended December 31, 2025:

			Millions of Dollars
	Stock Units	Weighted-Average Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2024	774,503	$ 50.75	
Granted	**4,737**	**100.90**	
Issued	**(193,286)**	**52.05**	**$ 18**
Outstanding at December 31, 2025	**585,954**	**$ 50.73**	

At December 31, 2025, there was no remaining unrecognized compensation cost to be recorded on the unvested stock-settled performance shares. The weighted-average grant date fair value of stock-settled PSUs granted during 2024 and 2023 was $110.39 and $112.50, respectively. The total fair value of stock-settled PSUs issued during 2024 and 2023 was $23 million and $29 million, respectively.

Cash-Settled
In connection with and immediately following the separation of our Downstream businesses in 2012, grants of new cash-settled PSUs, subject to a shortened performance period, were authorized. Once granted, these PSUs vest, absent employee election to defer, on the earlier of five years after the grant date of the award or the date the employee becomes eligible for retirement. For employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. Otherwise, we recognize compensation expense beginning on the grant date and ending on the date the PSUs are scheduled to vest. These PSUs are settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and thus are classified as liabilities on the balance sheet. Until settlement occurs, recipients of the PSUs receive a cash payment of a dividend equivalent that is charged to compensation expense.

Beginning in 2013, cash-settled PSUs vest upon settlement following the conclusion of the three-year performance period. We recognize compensation expense over the period beginning on the date of authorization and ending at the conclusion of the performance period. These PSUs will be settled in cash equal to the fair market value of a share of ConocoPhillips common stock per unit on the settlement date and are classified as liabilities on the balance sheet. For performance periods beginning before 2018, during the performance period, recipients of the PSUs do not receive a cash payment of a dividend equivalent, but after the performance period ends, until settlement in cash occurs, recipients of the PSUs receive a cash payment of a dividend equivalent that is charged to compensation expense. For the performance periods beginning in 2018 or later, recipients of the PSUs receive an accrued reinvested dividend equivalent that is charged to compensation expense. The accrued reinvested dividend is paid at the time of settlement, subject to the terms and conditions of the award.

The following summarizes our cash-settled Performance Share Program activity for the year ended December 31, 2025:

			Millions of Dollars
	Stock Units	Weighted-Average Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2024	89,583	$ 98.20	
Granted	**647,382**	**100.90**	
Settled	**(659,340)**	**100.14**	**$ 66**
Outstanding at December 31, 2025	**77,625**	**$ 94.00**	

At December 31, 2025, all outstanding cash-settled performance awards were fully vested with no remaining compensation cost to be recorded. The weighted-average grant date fair value of cash-settled PSUs granted during 2024 and 2023 was $110.39 and $112.50, respectively. The total fair value of cash-settled performance share awards settled during 2024 and 2023 was $171 million and $111 million, respectively.

From inception of the Performance Share Program through 2013, approved PSU awards were granted after the conclusion of performance periods. Beginning in February 2014, initial target PSU awards are issued near the beginning of new performance periods. These initial target PSU awards will terminate at the end of the performance periods and will be settled after the performance periods have ended. Also in 2014, initial target PSU awards were issued for open performance periods that began in prior years. For the open performance period beginning in 2012, the initial target PSU awards terminated at the end of the three-year performance period and were replaced with approved PSU awards. For the open performance period beginning in 2013, the initial target PSU awards terminated at the end of the three-year performance period and were settled after the performance period ended. There is no effect on recognition of compensation expense.

Other—In addition to the above active programs, we have outstanding shares of restricted stock and RSUs that were either issued as part of our non-employee director compensation program for current and former members of the company’s Board of Directors or as part of an executive compensation program that has been discontinued or assumed as a result of an acquisition. Generally, the recipients of the restricted shares or units receive a dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the year ended December 31, 2025:

			Millions of Dollars
	Stock Units	Weighted-Average Grant Date Fair Value	Total Fair Value
Outstanding at December 31, 2024	629,681	$ 60.22	
Granted	**43,292**	**98.68**	
Issued	**(110,284)**	**52.23**	**$ 12**
Outstanding at December 31, 2025	**562,689**	**$ 64.75**	

At December 31, 2025, all outstanding restricted stock and RSUs were fully vested with no remaining compensation cost to be recorded. The weighted-average grant date fair value of awards granted during 2024 and 2023 was $111.91 and $115.88, respectively. The total fair value of awards issued during 2024 and 2023 was $35 million and $46 million, respectively.

Note 15—Income Taxes

Components of income tax provision (benefit) were:

	Millions of Dollars		
	2025	2024	2023
Income Taxes			
Federal			
Current	$ **655**	629	1,054
Deferred	**537**	247	825
Foreign			
Current	**3,287**	3,249	2,931
Deferred	**33**	71	254
State and local			
Current	**177**	182	202
Deferred	**(21)**	49	65
Total tax provision (benefit)	$ **4,668**	4,427	5,331

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2025	2024
Deferred Tax Liabilities		
PP&E and intangibles	$ **16,244**	15,609
Inventory	**15**	91
Other	**160**	155
Total deferred tax liabilities	**16,419**	15,855
Deferred Tax Assets		
Benefit plan accruals	**330**	432
Asset retirement obligations and accrued environmental costs	**2,985**	2,799
Investments in joint ventures	**2,356**	2,269
Other financial accruals and deferrals	**507**	497
Loss and credit carryforwards	**4,048**	4,910
Other	**103**	187
Total deferred tax assets	**10,329**	11,094
Less: valuation allowance	**(5,926)**	(6,435)
Total deferred tax assets net of valuation allowance	**4,403**	4,659
Net deferred tax liabilities	$ **12,016**	11,196

At December 31, 2025, noncurrent assets and liabilities included deferred taxes of $221 million and $12,237 million, respectively. At December 31, 2024, noncurrent assets and liabilities included deferred taxes of $230 million and $11,426 million, respectively.

At December 31, 2025, the loss and credit carryforward deferred tax assets were primarily related to U.S. foreign tax credit carryforwards of $2.9 billion and various jurisdictions net operating loss and credit carryforwards of $1.1 billion.

At December 31, 2024, the loss and credit carryforward deferred tax assets were primarily related to U.S. foreign tax credit carryforwards of $3.3 billion and various jurisdictions net operating loss and credit carryforwards of $1.6 billion. In 2024, $1.2 billion of U.S. foreign tax credits expired. This reduction was partly offset by an increase of $700 million in our U.S. net operating loss, foreign tax credit carryforwards, and other credit carryforwards due to our acquisition of Marathon Oil. *See Note 3.*

The following table shows a reconciliation of the beginning and ending deferred tax asset valuation allowance for 2025, 2024 and 2023:

		Millions of Dollars		
		2025	2024	2023
Balance at January 1	$	**6,435**	7,656	8,049
Charged to expense (benefit)		**(59)**	(409)	(2)
Other*		**(450)**	(812)	(391)
Balance at December 31	$	**5,926**	6,435	7,656

**Represents changes due to deferred tax assets that have no impact to our effective tax rate, acquisitions/dispositions/revisions and the effect of translating foreign financial statements.*

Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. At December 31, 2025, we have maintained a valuation allowance with respect to substantially all U.S. foreign tax credit carryforwards, basis differences in our APLNG investment, and certain net operating loss carryforwards for various jurisdictions. During 2025, the valuation allowance movement charged to earnings primarily relates to the utilization of previously unrecognized capital loss carryforwards due to our agreement to the sale of our interest in the Ursa and Europa Fields, and the Ursa Pipeline Company LLC. During 2024, the valuation allowance movement charged to earnings primarily relates to the ability to utilize a portion of ConocoPhillips foreign tax credit carryforwards due to the acquisition of Marathon Oil. Other movements are primarily related to valuation allowances on expiring tax attributes. Based on our historical taxable income, expectations for the future and available tax-planning strategies, management expects deferred tax assets, net of valuation allowances, will primarily be realized as offsets to reversing deferred tax liabilities. *See Note 3*.

As a result of the acquisition of Marathon Oil, we utilized foreign tax credits previously offset by a valuation allowance. During the fourth quarter of 2024, a tax benefit of $394 million was recorded as a result of the acquisition and the subsequent utilization of the foreign tax credits. *See Note 3*.

At December 31, 2025, we had unremitted income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Deferred income taxes have not been provided on this amount, as we do not plan to initiate any action that would require the payment of income taxes. The estimated amount of additional tax, primarily local withholding tax, that would be payable on this income if distributed is approximately $314 million.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2025, 2024 and 2023:

		Millions of Dollars		
		2025	2024	2023
Balance at January 1	$	**377**	387	710
Additions based on tax positions related to the current year		**—**	3	5
Additions for tax positions of prior years		**13**	127	1
Reductions for tax positions of prior years		**—**	—	(9)
Settlements		**(3)**	(121)	(96)
Lapse of statute		**(13)**	(19)	(224)
Balance at December 31	$	**374**	377	387

Included in the balance of unrecognized tax benefits for 2025, 2024 and 2023 were $365 million, $368 million and $378 million, respectively, which, if recognized, would impact our effective tax rate.

The balance of the unrecognized tax benefits decreased in 2025 due to the lapsing of the statute of limitations on certain of our foreign subsidiaries, partially offset by additions on tax positions related to prior years on certain of our foreign subsidiaries.

The balance of the unrecognized tax benefits decreased in 2024 due to the resolution of certain items with U.S. and Norwegian taxing authorities. The balance of our unrecognized tax benefits increased in 2024 primarily due to U.S. tax credits acquired through our acquisition of Marathon Oil. *See Note 3*.

The balance of the unrecognized tax benefits decreased in 2023 due to the lapsing of the statute of limitations on certain of our foreign subsidiaries of $224 million as well as the closing of our 2018 Canadian domestic audit that resulted in a reduction of $92 million.

At December 31, 2025, 2024 and 2023, accrued liabilities for interest and penalties totaled $47 million, $26 million and $45 million, respectively, net of accrued income taxes. Interest and penalties resulted in a reduction to earnings of $21 million in 2025, an increase to earnings of $19 million in 2024 and a reduction to earnings of $10 million in 2023.

We file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: Canada (2018), Norway (2024) and U.S. (2021). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. Consequently, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. Within the next twelve months, we may have audit periods close that could significantly impact our total unrecognized tax benefits. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income (loss) before income taxes, with a reconciliation of tax at the federal statutory rate to the provision for income taxes, under newly adopted ASU 2023-09 *"Improvements to Income Tax Disclosures"*, which we adopted for the year ended 2025 on a retrospective basis were:

	Millions of Dollars			Percent of Pre-Tax Income (Loss)		
	2025	2024	2023	**2025**	2024	2023
Income (loss) before income taxes						
United States	$ **6,176**	6,731	9,472	**48.8 %**	49.2	58.2
Foreign	**6,480**	6,941	6,816	**51.2**	50.8	41.8
	$ **12,656**	13,672	16,288	**100.0 %**	100.0	100.0
U.S. federal statutory tax rate	$ **2,658**	2,871	3,421	**21.0 %**	21.0	21.0
State income taxes, net of federal Income tax effect*	**127**	187	214	**1.0**	1.4	1.3
Foreign tax effects						
Norway						
Statutory tax rate difference between Norway and U.S.	**1,020**	1,205	1,298	**8.1**	8.8	8.0
Other	**(48)**	(97)	(96)	**(0.4)**	(0.7)	(0.5)
Libya				**—**	—	—
Additional foreign income tax	**1,087**	1,027	1,072	**8.6**	7.5	6.6
Other	**(25)**	(17)	(11)	**(0.2)**	(0.1)	(0.1)
Australia				**—**	—	—
Equity in earnings, net of tax	**(160)**	(230)	(242)	**(1.3)**	(1.7)	(1.5)
Other	**(6)**	(3)	(12)	**—**	—	(0.1)
Other foreign jurisdictions	**102**	(126)	51	**0.8**	(0.9)	0.3
Effect of cross-border tax laws	**44**	59	21	**0.4**	0.4	0.1
Tax Credits	**(21)**	—	—	**(0.2)**	—	—
Valuation allowances	**(60)**	(409)	(25)	**(0.5)**	(3.0)	(0.2)
Nontaxable or nondeductible items	**(24)**	18	(44)	**(0.2)**	0.1	(0.3)
Changes in unrecognized tax benefits	**(11)**	(54)	(312)	**(0.1)**	(0.4)	(1.9)
Other Adjustments	**(15)**	(4)	(4)	**(0.1)**	—	—
Total	$ **4,668**	4,427	5,331	**36.9 %**	32.4	32.7

**For 2025, state taxes in Alaska contributed to the majority (greater than 50 percent) of the tax effect in this category. For 2024, state taxes in Alaska contributed to the majority (greater than 50 percent) of the tax effect in this category. For 2023, state taxes in Alaska and California contributed to the majority (greater than 50 percent) of the tax effect in this category.*

Our effective tax rate for 2025 was driven by our jurisdictional tax rates for this profit mix with a favorable impact from the utilization of previously unrecognized capital loss carryforwards.

Our effective tax rate for 2024 was driven by our jurisdictional tax rates for this profit mix with a favorable impact from the acquisition of Marathon Oil, enabling the utilization of foreign tax credits previously offset by a valuation allowance. *See Note 3*.

Our effective tax rate for 2023 was driven by our jurisdictional tax rates for this profit mix with a favorable impact from routine tax credits. The adjustment to tax reserves primarily relates to the lapsing of the statute of limitations on certain of our foreign subsidiaries and the closing of the 2018 Canadian domestic audit.

Note 16—Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) in the equity section of the balance sheet included:

	Millions of Dollars					
		Defined Benefit Plans	Net Unrealized Holding Gain/(Loss) on Securities	Foreign Currency Translation	Unrealized Gain/(Loss) on Hedging Activities	Accumulated Other Comprehensive Income/(Loss)
December 31, 2022	$	(448)	(11)	(5,541)	—	(6,000)
Other comprehensive income (loss)		55	13	197	62	327
December 31, 2023		(393)	2	(5,344)	62	(5,673)
Other comprehensive income (loss)		3	1	(760)	(44)	(800)
December 31, 2024		(390)	3	(6,104)	18	(6,473)
Other comprehensive income (loss)		**55**	**5**	**502**	**—**	**562**
December 31, 2025	**$**	**(335)**	**8**	**(5,602)**	**18**	**(5,911)**

Note 17—Cash Flow Information

	Millions of Dollars			
		2025	2024	2023
Noncash Investing and Financing Activities				
Increase (decrease) in PP&E related to an increase (decrease) in asset retirement obligations, excluding acquisitions	$	**12**	268	727
Fair value of contingent consideration on acquisition		**—**	—	320
Cash Payments				
Interest		**757**	806	701
Income Taxes				
Federal taxes		**1,077**	296	757
Foreign taxes				
Norway		**1,758**	1,580	2,758
Libya		**1,461**	1,280	1,317
Other foreign		**374**	304	349
State taxes		**152**	161	225
Total income taxes	$	**4,822**	3,621	5,406
Net Sales (Purchases) of Investments				
Short-term investments purchased	$	**(1,249)**	(2,606)	(1,463)
Short-term investments sold		**1,751**	3,567	3,574
Long-term Investments purchased		**(861)**	(747)	(867)
Long-term Investments sold		**304**	201	129
Total sales (purchases) of investments	$	**(55)**	415	1,373

The following items are included in the "Cash flows from operating activities" section of our consolidated cash flows.

In 2025, we made a total of $116 million in contributions to our U.S. qualified pension plan.

For additional information on cash and non-cash changes to our consolidated balance sheet, see *Note 3 and Note 11* for our acquisition of Marathon Oil and acquisition of the remaining working interest in Surmont.

Note 18—Sales and Other Operating Revenues

Revenue from Contracts with Customers

The following table provides further disaggregation of our consolidated sales and other operating revenues:

	Millions of Dollars		
	2025	2024	2023
Revenue from contracts with customers	$ **51,824**	49,418	48,522
Revenue from contracts outside the scope of ASC Topic 606			
Physical contracts meeting the definition of a derivative	**7,201**	5,483	8,203
Financial derivative contracts	**(81)**	(156)	(584)
Consolidated sales and other operating revenues	$ **58,944**	54,745	56,141

Revenues from contracts outside the scope of ASC Topic 606, "Revenue from Contracts with Customers," relate primarily to physical gas contracts at market prices, which qualify as derivatives accounted for under ASC Topic 815, "Derivatives and Hedging," and for which we have not elected NPNS. There is no significant difference in contractual terms or the policy for recognition of revenue from these contracts and those within the scope of ASC Topic 606. Further disaggregation of revenues is provided in *Note 22 - Segment Disclosures and Related Information.*

Practical Expedients

Typically, our commodity sales contracts are less than 12 months in duration; however, in certain specific cases may extend longer, which may be out to the end of field life. We have long-term commodity sales contracts which use prevailing market prices at the time of delivery, and under these contracts, the market-based variable consideration for each performance obligation (i.e., delivery of commodity) is allocated to each wholly unsatisfied performance obligation within the contract. Accordingly, we have applied the practical expedient allowed in ASC Topic 606 and do not disclose the aggregate amount of the transaction price allocated to performance obligations or when we expect to recognize revenues that are unsatisfied as of the end of the reporting period.

Receivables from Contracts with Customers

At December 31, 2025, the "Accounts and notes receivable" line on our consolidated balance sheet included trade receivables of $4,416 million compared with $5,398 million at December 31, 2024, and included both contracts with customers within the scope of ASC Topic 606 and those that are outside the scope of ASC Topic 606. We typically receive payment within 30 days or less (depending on the terms of the invoice) once delivery is made. Revenues that are outside the scope of ASC Topic 606 relate primarily to physical natural gas sales contracts at market prices for which we do not elect NPNS and are therefore accounted for as a derivative under ASC Topic 815. There is little distinction in the nature of the customer or credit quality of trade receivables associated with natural gas sold under contracts for which NPNS has not been elected compared with trade receivables where NPNS has been elected.

Note 19—Related Party Transactions

The following tables summarize the related party balances and activities which are primarily with equity affiliates:

	Millions of Dollars	
	December 31 2025	December 31 2024
Balance Sheet		
Accounts and notes receivable	$ **79**	74
Accounts payable	**64**	57

	Millions of Dollars		
	2025	2024	2023
Income Statement			
Operating revenues and other income	$ **73**	88	90
Purchased commodities	**1**	—	—
Operating expenses and selling, general and administrative expenses	**286**	246	282

Note 20—Other Financial Information

		Millions of Dollars		
		2025	2024	2023
Interest and Debt Expense				
Incurred				
Debt	$	**1,176**	941	824
Other		**63**	90	109
		1,239	1,031	933
Capitalized		**(384)**	(248)	(153)
Expensed	$	**855**	783	780
Other Income				
Interest income	$	**311**	402	412
Other, net		**227**	50	73
Total	$	**538**	452	485
Research and Development Expenditures—expensed	$	**78**	81	81
Shipping and Handling Costs	$	**2,438**	1,958	1,695
Foreign Currency Transaction (Gains) Losses—after-tax				
Alaska	$	**—**	—	—
Lower 48		**—**	—	—
Canada		**20**	(35)	11
Europe, Middle East and North Africa		**30**	(37)	(39)
Asia Pacific		**(33)**	(1)	12
Segments Total		**17**	(73)	(16)
Corporate and Other		**(17)**	36	86
Total	$	**—**	(37)	70

		Millions of Dollars	
		2025	2024
Properties, Plants and Equipment			
Proved properties	$	**167,969**	155,364
Unproved properties		**10,822**	15,490
Other		**4,844**	4,574
Gross properties, plants and equipment		**183,635**	175,428
Less: Accumulated depreciation, depletion and amortization		**(90,396)**	(81,072)
Net properties, plants and equipment	$	**93,239**	94,356

Note 21—Earnings Per Share

The following table presents the calculation of net income (loss) available to common shareholders and basic and diluted EPS for the years ended December 31, 2025, 2024, and 2023. For each of the periods with net income presented in the table below, diluted EPS calculated under the two-class method was more dilutive.

	Millions of Dollars (except per share amounts)		
Years Ended December 31	**2025**	2024	2023
Basic earnings per share			
Net income (loss)	$ **7,988**	9,245	10,957
Less: Dividends and undistributed earnings allocated to participating securities	**27**	27	35
Net income (loss) available to common shareholders	$ **7,961**	9,218	10,922
Weighted-average common shares outstanding (in millions)	**1,252**	1,179	1,203
Net income (loss) per share of common stock	$ **6.36**	7.82	9.08
Diluted earnings per share			
Net income (loss) available to common shareholders	$ **7,961**	9,218	10,922
Weighted-average common shares outstanding (in millions)	**1,252**	1,179	1,203
Add: Dilutive impact of options and unvested non-participating RSU/PSUs	**1**	2	3
Weighted-average diluted shares outstanding (in millions)	**1,253**	1,181	1,206
Net income (loss) per share of common stock	$ **6.35**	7.81	9.06

Note 22—Segment Disclosures and Related Information

We explore for, produce, transport and market crude oil, bitumen, natural gas, LNG and NGLs on a worldwide basis. We manage our operations through five operating segments, which are primarily defined by geographic region: Alaska; Lower 48 (L48); Canada; Europe, Middle East and North Africa (EMENA); and Asia Pacific (AP).

Corporate and Other (Corporate) represents income and costs not directly associated with an operating segment, such as most interest expense, premiums on early retirement of debt, corporate overhead and certain technology activities, including licensing revenues. Corporate assets include all cash and cash equivalents and short-term investments.

Effective in the fourth quarter of 2025, we determined that our former Other International operating segment, which consisted of activities associated with prior operations in other countries, was no longer an operating segment. Residual results are aggregated into Corporate. Our historical operating segment reporting has been recast to reflect this change.

Our chief operating decision maker (CODM) is our Chairman of the Board of Directors and Chief Executive Officer, who evaluates performance and allocates resources among our operating segments based on each segment's net income (loss). This is done through the annual budget and forecasting process.

Segment accounting policies are the same as those in *Note 1.* Intersegment sales are at prices that approximate market. The significant segment expense categories and amounts in the tables below align with segment-level information that is regularly provided to the CODM.

2025 Segment level net income (loss)

Year Ended December 31, 2025	Millions of Dollars							
	Alaska	L48	Canada	EMENA	AP	Segments Total	Corporate	Consolidated Total
Segment sales and other operating revenues								
Sales and other operating revenues	$ 5,638	41,404	5,600	6,485	1,770	60,897	63	60,960
Intersegment eliminations	—	(9)	(1,975)	(1)	—	(1,985)	(31)	(2,016)
Consolidated sales and other operating revenues[#*]	5,638	41,395	3,625	6,484	1,770	58,912	32	58,944
Significant segment expenses								
Production and operating expenses	2,158	5,856	833	962	367	10,176	155	10,331
DD&A	1,399	8,121	556	912	460	11,448	52	11,500
Income tax provision (benefit)	271	1,380	236	2,820	238	4,945	(277)	4,668
Total	3,828	15,357	1,625	4,694	1,065	26,569	(70)	26,499
Other segment items								
Equity in earnings of affiliates	(1)	(11)	—	(558)	(762)	(1,332)	(3)	(1,335)
Interest income	—	—	—	—	(8)	(8)	(303)	(311)
Interest and debt expense	—	—	—	—	—	—	855	855
Other**	1,081	20,785	1,259	1,124	308	24,557	691	25,248
Total	1,080	20,774	1,259	566	(462)	23,217	1,240	24,457
Net income (loss)	$ 730	5,264	741	1,224	1,167	9,126	(1,138)	7,988

[#]Includes revenue from physical contracts meeting the definition of a derivative that are outside the scope of ASC Topic 606 for the L48, Canada and EMENA segments of $5.7 billion, $0.7 billion and $0.8 billion, respectively.

**In 2025, sales by our L48 segment to a certain pipeline company accounted for approximately $5.3 billion or approximately 10 percent of our total consolidated sales and other operating revenues.*

***Other segment items not required to be separately disclosed for each reportable segment include:*

***Gain (loss) on disposition:** L48, EMENA and Corporate*

***Other income:** L48, Canada, EMENA, AP and Corporate*

***Purchased commodities:** Alaska, L48, Canada, EMENA and AP*

***Selling, general and administrative expenses, Exploration expenses, Taxes other than income taxes and Accretion on discounted liabilities:** Alaska, L48, Canada, EMENA, AP and Corporate*

***Impairments:** Alaska, L48 and Canada*

***Foreign currency transaction (gain) loss:** Canada, EMENA, AP and Corporate*

***Other expenses:** Alaska, L48, Canada, EMENA and Corporate*

Other segment disclosures

Year Ended December 31, 2025	Millions of Dollars							
	Alaska	L48	Canada	EMENA	AP	Segments Total	Corporate	Consolidated Total
Equity investments	$ 3	—	—	2,268	4,926	7,197	1,636	8,833
Total assets	20,224	61,933	9,978	10,554	8,273	110,962	10,977	121,939
Capital expenditures and investments	3,607	6,702	593	1,194	342	12,438	115	12,553

2024 Segment level net income (loss)

Year Ended December 31, 2024	Millions of Dollars							
	Alaska	L48	Canada	EMENA	AP	Segments Total	Corporate	Consolidated Total
Segment sales and other operating revenues								
Sales and other operating revenues	$ 6,553	37,028	5,636	5,788	1,847	56,852	54	56,906
Intersegment eliminations	—	(2)	(2,122)	—	—	(2,124)	(37)	(2,161)
Consolidated sales and other operating revenues[#]*	6,553	37,026	3,514	5,788	1,847	54,728	17	54,745
Significant segment expenses								
Production and operating expenses	1,951	4,751	902	671	384	8,659	92	8,751
DD&A	1,299	6,442	639	761	425	9,566	33	9,599
Income tax provision (benefit)	480	1,462	228	2,854	211	5,235	(808)	4,427
Total	3,730	12,655	1,769	4,286	1,020	23,460	(683)	22,777
Other segment items								
Equity in earnings of affiliates	1	(5)	—	(586)	(1,089)	(1,679)	(26)	(1,705)
Interest income	—	—	—	—	(8)	(8)	(394)	(402)
Interest and debt expense	—	—	—	—	—	—	783	783
Other**	1,496	19,201	1,033	899	200	22,829	1,218	24,047
Total	1,497	19,196	1,033	313	(897)	21,142	1,581	22,723
Net income (loss)	$ 1,326	5,175	712	1,189	1,724	10,126	(881)	9,245

[#]Includes revenue from physical contracts meeting the definition of a derivative that are outside the scope of ASC Topic 606 for the L48, Canada and EMENA segments of $4.2 billion, $0.5 billion and $0.8 billion, respectively.

**In 2024, sales by our L48 segment to a certain pipeline company accounted for approximately $6.7 billion or approximately 12 percent of our total consolidated sales and other operating revenues.*

***Other segment items not required to be separately disclosed for each reportable segment include:*

***Gain (loss) on dispositions:** L48, Canada, EMENA and Corporate*

***Other income; Selling, general and administrative expenses; Exploration expenses; Taxes other than income taxes; and Accretion on discounted liabilities:** Alaska, L48, Canada, EMENA, AP and Corporate*

***Purchased Commodities and Impairments:** Alaska, L48, Canada and EMENA*

***Foreign currency transaction (gain) loss:** Canada, EMENA and Corporate*

***Other expenses:** Alaska, L48, EMENA and Corporate*

Other segment disclosures

Year Ended December 31, 2024	Millions of Dollars							
	Alaska	L48	Canada	EMENA	AP	Segments Total	Corporate	Consolidated Total
Equity investments	$ 3	123	—	1,948	4,977	7,051	1,559	8,610
Total assets	18,030	66,977	9,513	9,770	8,390	112,680	10,100	122,780
Capital expenditures and investments	3,194	6,510	551	1,021	370	11,646	472	12,118

2023 Segment level net income (loss)

Year Ended December 31, 2023	Millions of Dollars							
	Alaska	L48	Canada	EMENA	AP	Segment Totals	Corporate	Consolidated Total
Segment sales and other operating revenues								
Sales and other operating revenues	$ 7,098	38,244	4,873	5,854	1,913	57,982	63	58,045
Intersegment eliminations	—	(7)	(1,867)	—	—	(1,874)	(30)	(1,904)
Consolidated sales and other operating revenues[#]* *	7,098	38,237	3,006	5,854	1,913	56,108	33	56,141
Significant segment expenses								
Production and operating expenses	1,829	4,199	619	593	391	7,631	62	7,693
DD&A	1,061	5,722	420	587	455	8,245	25	8,270
Income tax provision (benefit)	642	1,763	26	3,065	42	5,538	(207)	5,331
Total	3,532	11,684	1,065	4,245	888	21,414	(120)	21,294
Other segment items								
Equity in earnings of affiliates	(1)	9	—	(580)	(1,151)	(1,723)	3	(1,720)
Interest income	—	—	—	(1)	(8)	(9)	(403)	(412)
Interest and debt expense	—	—	—	—	—	—	780	780
Other**	1,789	20,083	1,539	1,001	223	24,635	607	25,242
Total	1,788	20,092	1,539	420	(936)	22,903	987	23,890
Net income (loss)	$ 1,778	6,461	402	1,189	1,961	11,791	(834)	10,957

[#]Includes revenue from physical contracts meeting the definition of a derivative that are outside the scope of ASC Topic 606 for the L48, Canada and EMENA segments of $6.6 billion, $1.3 billion and $0.3 billion, respectively.

**In 2023, sales by our Lower 48 segment to a certain pipeline company accounted for approximately $5.8 billion or approximately 10 percent of our total consolidated sales and other operating revenues.*

***Other segment items not required to be separately disclosed for each reportable segment include:*

***Gain (loss) on dispositions:** Alaska, L48, AP and Corporate*

***Other income; Selling, general and administrative expenses; Exploration expenses; Taxes other than income taxes; and Accretion on discounted liabilities:** Alaska, L48, Canada, EMENA, AP and Corporate*

***Purchased commodities:** Alaska, L48, Canada, EMENA and AP*

***Impairments:** L48, Canada and Corporate*

***Foreign currency transaction (gain) loss:** Canada, EMENA, AP and Corporate*

***Other expenses:** Alaska, L48, EMENA and Corporate*

Other segment disclosures

Year Ended December 31, 2023	Millions of Dollars							
	Alaska	L48	Canada	EMENA	AP	Segment Totals	Corporate	Consolidated Total
Equity investments	$ 32	118	—	1,191	5,419	6,760	1,145	7,905
Total assets	16,174	42,415	10,277	8,396	8,903	86,165	9,759	95,924
Capital expenditures and investments	1,705	6,487	456	1,111	354	10,113	1,135	11,248

Sales and Other Operating Revenues by Product

Consolidated sales and other operating revenues

	Millions of Dollars		
	2025	2024	2023
Crude oil	$ **39,068**	39,010	37,833
Natural gas	**8,854**	6,444	10,725
Natural gas liquids	**3,705**	2,889	2,609
Other*	**7,317**	6,402	4,974
Total	$ **58,944**	54,745	56,141

**Includes bitumen, power and LNG.*

Revenue from physical contracts meeting the definition of a derivative outside the scope of ASC Topic 606

	Millions of Dollars		
	2025	2024	2023
Crude oil	$ **494**	376	143
Natural gas	**5,465**	3,753	6,622
Power	**1,242**	1,354	1,438
Total	$ **7,201**	5,483	8,203

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues*			Long-Lived Assets**		
	2025	2024	2023	**2025**	2024	2023
U.S.	$ **46,611**	43,480	45,101	**77,453**	79,141	53,955
International	**12,333**	11,265	11,040	**24,619**	23,825	23,994
Worldwide consolidated	$ **58,944**	54,745	56,141	**102,072**	102,966	77,949

**Sales and other operating revenues are attributable to countries based on the location of their selling operation.*
*** Defined as net PP&E plus equity investments and advances to affiliated companies.*

Note 23—New Accounting Standards

In November 2024, the FASB issued ASU No. 2024-03, “Disaggregation of Income Statement Expenses” to improve the disclosures about a public business entity’s expenses (including purchases of inventory, employee compensation, depreciation, depletion and amortization) in commonly presented expense captions. The ASU will impact our financial statement disclosures only and will be applied prospectively with retrospective application permitted. The ASU is effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, and early adoption is permitted. We are currently evaluating the impact of the adoption of this ASU.

Oil and Gas Operations (Unaudited)

In accordance with FASB ASC Topic 932, "Extractive Activities—Oil and Gas," and regulations of the SEC, we are making certain supplemental disclosures about our oil and gas exploration and production operations.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities in our operating segments. As a result, amounts reported as equity affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. Our disclosures by geographic area include the U.S., Canada, Europe, Asia Pacific/Middle East (inclusive of equity affiliates) and Africa.

As required by current authoritative guidelines, the estimated future date when an asset will be permanently shut down for economic reasons is based on historical 12-month first-of-month average prices and current costs. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Generally, our proved reserves decrease as prices decline and increase as prices rise.

Our proved reserves include estimated quantities related to PSCs, which are reported under the "economic interest" method, as well as variable-royalty regimes, and are subject to fluctuations in commodity prices, recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2025, approximately three percent of our total proved reserves were under PSCs, located in our Asia Pacific/Middle East and Africa geographic reporting areas, and six percent of our total proved reserves were under a variable-royalty regime, located in our Canada geographic reporting area.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved 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 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 it will commence the project within a reasonable time.

Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared with the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence provided by reliable technologies exists that establishes reasonable certainty of economic producibility at greater distances. As defined by SEC regulations, reliable technologies may be used in reserve estimation when they have been demonstrated in the field to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. The technologies and data used in the estimation of our proved reserves include, but are not limited to, performance-based methods, volumetric-based methods, geologic maps, seismic interpretation, well logs, well test data, core data, analogy and statistical analysis.

We have a company-wide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geoscientists and reservoir engineers in our business units around the world. As part of our internal control process, each business unit's reserves processes and controls are reviewed annually by an internal team which is headed by the company's Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geoscientists, finance personnel and a senior representative from DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm, reviews the business unit's reserves for adherence to SEC guidelines and company policy through on-site visits, teleconferences and review of documentation. In addition to providing independent reviews, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management. The team is responsible for communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

During 2025, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2025, were reviewed by D&M. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips' technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management's intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M's opinion was the general processes and controls employed by ConocoPhillips in estimating its December 31, 2025 proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M's report is included as Exhibit 99 of this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the processes and internal controls used in the preparation of the company's reserves estimates is the Manager of Reserves Compliance and Reporting. This individual holds a master's degree in reservoir engineering. He is a member of the Society of Petroleum Engineers with over 20 years of oil and gas industry experience and has held positions of increasing responsibility in reservoir engineering, subsurface and asset management in the U.S. and several international field locations.

Engineering estimates of the quantities of proved reserves are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

Proved Reserves

Years Ended December 31	Crude Oil									
	Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed and Undeveloped										
End of 2022	955	1,508	2,463	8	175	119	210	2,975	93	3,068
Revisions	(57)	126	69	1	(1)	8	10	87	1	88
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	2	2	—	—	—	—	2	—	2
Extensions and discoveries	219	54	273	15	3	19	—	310	—	310
Production	(64)	(202)	(266)	(3)	(23)	(22)	(17)	(331)	(5)	(336)
Sales	—	(11)	(11)	—	—	—	—	(11)	—	(11)
End of 2023	1,053	1,477	2,530	21	154	124	203	3,032	89	3,121
Revisions	5	185	190	5	(5)	15	52	257	—	257
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	23	364	387	—	—	—	25	412	—	412
Extensions and discoveries	14	29	43	9	—	—	—	52	24	76
Production	(62)	(211)	(273)	(6)	(25)	(22)	(18)	(344)	(5)	(349)
Sales	—	(3)	(3)	—	—	—	—	(3)	—	(3)
End of 2024	1,033	1,841	2,874	29	124	117	262	3,406	108	3,514
Revisions	(9)	237	228	(6)	1	14	18	255	—	255
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	46	64	110	4	—	—	—	114	—	114
Production	(63)	(269)	(332)	(6)	(23)	(21)	(25)	(407)	(5)	(412)
Sales	—	(47)	(47)	—	—	—	—	(47)	—	(47)
End of 2025	1,007	1,826	2,833	21	102	110	255	3,321	103	3,424

Years Ended December 31	Crude Oil									
	Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed										
End of 2022	867	828	1,695	5	124	102	191	2,117	58	2,175
End of 2023	790	793	1,583	7	109	91	181	1,971	54	2,025
End of 2024	767	1,122	1,889	11	101	88	208	2,297	49	2,346
End of 2025	730	1,015	1,745	9	89	91	214	2,148	44	2,192
Undeveloped										
End of 2022	88	680	768	3	51	17	19	858	35	893
End of 2023	263	684	947	14	45	33	22	1,061	35	1,096
End of 2024	266	719	985	18	23	29	54	1,109	59	1,168
End of 2025	277	811	1,088	12	13	19	41	1,173	59	1,232

**All Equity Affiliate reserves are located in our Asia Pacific/Middle East Region.*

Notable changes in proved crude oil reserves in the three years ended December 31, 2025, included:

- *Revisions*: In 2025, upward revisions in Lower 48 were due to development drilling of 407 million barrels, technical revisions of 18 million barrels, and 13 million barrels due to lower operating costs, partially offset by downward revisions of 160 million barrels for changes in development plans and 41 million barrels due to lower prices. Upward revisions in Africa were in Libya, with development plan updates of 12 million barrels and technical revisions of 6 million barrels. Upward revisions of 14 million barrels in the consolidated operations in Asia Pacific/Middle East were split between China, where technical revisions contributed 4 million barrels and development plan updates 3 million barrels, and Malaysia, with upward technical revisions of 7 million barrels. In Alaska, downward revisions of 9 million barrels were due to lower prices of 21 million barrels, partially offset by 7 million barrels of upward technical revisions and 5 million barrels due to development plan updates. Downward revisions in Canada were due to technical revisions of 4 million barrels and changes in development plans of 2 million barrels.

  In 2024, upward revisions in Lower 48 were due to development drilling of 298 million barrels and technical revisions of 28 million barrels, partially offset by downward revisions of 114 million barrels for changes in development plans, 23 million barrels due to lower prices and increasing operating costs of 4 million barrels. An upward revision of 52 million barrels in Africa was due to an increase in development plans in Libya. In the consolidated operations in Asia Pacific/Middle East, upward revisions of 15 million barrels were primarily due to the project sanction of Bohai Bay Phase 5 in China. Upward revisions of 5 million barrels in Canada were due to technical revisions. In Alaska, where future production is constrained by the Trans-Alaska Pipeline System minimum flow limit, updated total North Slope development phasing indicated that the flow limit will be reached later than previously premised, resulting in upward revisions of 22 million barrels. Further upward revisions in Alaska include development plan changes of 8 million barrels. These were partially offset by downward revisions due to increasing operating costs of 15 million barrels and 10 million barrels due to technical revisions. Downward revisions in Europe were due to technical revisions of 3 million barrels and development plan changes of 2 million barrels.

  In 2023, upward revisions in Lower 48 were due to development drilling of 161 million barrels and technical revisions in the unconventional plays of 31 million barrels, partially offset by downward revisions of 52 million barrels due to lower prices and 14 million barrels for changes in development plans. An upward revision of 10 million barrels in Africa was primarily development drilling in Libya. Upward revisions of 8 million barrels in the consolidated operations in Asia Pacific/Middle East were due to technical revisions. In Alaska, where future production is constrained by the Trans-Alaska Pipeline System minimum flow limit, updated total North Slope development phasing indicated that the flow limit will be reached earlier than previously premised, resulting in downward revisions of 25 million barrels. Further downward revisions in Alaska include development plan changes of 14 million barrels, cost escalation of 13 million barrels, and 7 million barrels due to lower prices, partially offset by 2 million barrels of technical revisions.

- *Purchases*: In 2024, our acquisition of Marathon Oil resulted in purchases for Lower 48, as well as for Africa, representing reserves in Equatorial Guinea. Purchases in Alaska represent the acquisition of additional interest in the Kuparuk River and Prudhoe Bay units.

- *Extensions and discoveries*: In 2025, Lower 48 extensions and discoveries were primarily within unconventional plays in the Permian Basin. Alaska extensions and discoveries were primarily in the Greater Kuparuk area, with 34 million barrels in the Coyote development and 8 million barrels in the Nuna project, as well as 4 million barrels from Western North Slope projects. Extensions and discoveries in Canada were in Montney.

  In 2024, Lower 48 extensions and discoveries were primarily within unconventional plays in the Permian Basin. Alaska extensions and discoveries were primarily due to Nuna and other Western North Slope projects. Extensions and discoveries in Canada were in Montney. Extensions and discoveries in our equity affiliates were in the Middle East.

  In 2023, extensions and discoveries in Alaska were driven primarily by the Willow and Nuna projects. Lower 48 extensions and discoveries were primarily within unconventional plays in the Permian Basin. Extensions and discoveries in Canada and Asia Pacific/Middle East were driven primarily by Montney and Bohai Phase 4B in China, respectively.

- *Sales*: In 2025, Lower 48 sales represent noncore asset dispositions in the Anadarko Basin of 17 million barrels, offshore US assets of 14 million barrels, and other assets of 16 million barrels, primarily in the Permian Basin.

Years Ended December 31	Natural Gas Liquids									
	Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed and Undeveloped										
End of 2022	78	749	827	5	13	—		845	50	895
Revisions	(1)	119	118	—	2	—		120	1	121
Improved recovery	—	—	—	—	—	—		—	—	—
Purchases	—	1	1	—	—	—		1	—	1
Extensions and discoveries	—	20	20	6	—	—		26	—	26
Production	(5)	(90)	(95)	(1)	(2)	—		(98)	(3)	(101)
Sales	—	(2)	(2)	—	—	—		(2)	—	(2)
End of 2023	72	797	869	10	13	—	—	892	48	940
Revisions	4	123	127	1	(2)	—	—	126	—	126
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	1	209	210	—	—	—	14	224	—	224
Extensions and discoveries	—	15	15	3	—	—	—	18	17	35
Production	(6)	(102)	(108)	(2)	(2)	—	—	(112)	(3)	(115)
Sales	—	(1)	(1)	—	—	—	—	(1)	—	(1)
End of 2024	71	1,041	1,112	12	9	—	14	1,147	62	1,209
Revisions	2	181	183	—	—	—	—	183	—	183
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	34	34	2	—	—	—	36	—	36
Production	(6)	(139)	(145)	(2)	(1)	—	(2)	(150)	(3)	(153)
Sales	—	(50)	(50)	—	—	—	—	(50)	—	(50)
End of 2025	67	1,067	1,134	12	8	—	12	1,166	59	1,225

Years Ended December 31	Natural Gas Liquids									
	Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed										
End of 2022	78	409	487	3	10	—		500	31	531
End of 2023	72	426	498	4	9	—		511	28	539
End of 2024	71	653	724	6	7	—	13	750	25	775
End of 2025	67	620	687	6	7	—	11	711	22	733
Undeveloped										
End of 2022	—	340	340	2	3	—		345	19	364
End of 2023	—	371	371	6	4	—		381	20	401
End of 2024	—	388	388	6	2	—	1	397	37	434
End of 2025	—	447	447	6	1	—	1	455	37	492

**All Equity Affiliate reserves are located in our Asia Pacific/Middle East Region.*

Notable changes in proved NGL reserves in the three years ended December 31, 2025, included:

- *Revisions*: In 2025, upward revisions in Lower 48 were due to additional development drilling of 224 million barrels, technical revisions of 49 million barrels, and 13 million barrels due to lower operating costs. This was partly offset by changes in development plan of 89 million barrels and lower prices of 16 million barrels.

  In 2024, upward revisions in Lower 48 were due to additional development drilling of 164 million barrels and technical revisions of 52 million barrels. This was partially offset by development plan changes of 73 million barrels and lower prices impacting 20 million barrels.

  In 2023, upward revisions in Lower 48 were due to additional development drilling in the unconventional plays of 86 million barrels and technical revisions of 71 million barrels. This was partially offset by lower prices impacting 34 million barrels and development plan changes of 4 million barrels.

- *Purchases*: Purchases in 2024 were due to our acquisition of Marathon Oil, resulting in purchases for Lower 48 as well as in Africa, representing reserves in Equatorial Guinea.

- *Extensions and discoveries*: In 2025, Lower 48 extensions and discoveries were primarily within unconventional plays in the Permian Basin.

  In 2024, Lower 48 extensions and discoveries were primarily within unconventional plays in the Permian Basin. Extensions and discoveries in our equity affiliates were in the Middle East.

  In 2023, extensions and discoveries in Lower 48 were primarily within unconventional plays in the Permian Basin. Canada extensions and discoveries were in Montney.

- *Sales*: In 2025, Lower 48 sales represent noncore asset dispositions in the Anadarko Basin of 40 million barrels, offshore US assets of 2 million barrels, and other assets of 8 million barrels, primarily in the Permian Basin.

Years Ended December 31	Natural Gas Billions of Cubic Feet									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed and Undeveloped										
End of 2022	2,502	4,742	7,244	94	862	326	241	8,767	5,753	14,520
Revisions	(243)	521	278	27	73	6	(57)	327	(90)	237
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	4	4	—	—	—	—	4	—	4
Extensions and discoveries	—	121	121	144	1	4	—	270	58	328
Production	(84)	(570)	(654)	(25)	(113)	(24)	(12)	(828)	(446)	(1,274)
Sales	—	(97)	(97)	—	—	—	—	(97)	—	(97)
End of 2023	2,175	4,721	6,896	240	823	312	172	8,443	5,275	13,718
Revisions	102	356	458	15	47	9	3	532	(26)	506
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	47	1,177	1,224	—	—	—	310	1,534	—	1,534
Extensions and discoveries	—	87	87	67	1	—	—	155	1,075	1,230
Production	(78)	(599)	(677)	(43)	(125)	(25)	(17)	(887)	(454)	(1,341)
Sales	—	(6)	(6)	—	—	—	—	(6)	—	(6)
End of 2024	2,246	5,736	7,982	279	746	296	468	9,771	5,870	15,641
Revisions	(76)	1,167	1,091	(29)	45	123	18	1,248	319	1,567
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	187	187	47	—	—	—	234	67	301
Production	(77)	(793)	(870)	(49)	(126)	(29)	(68)	(1,142)	(442)	(1,584)
Sales	—	(406)	(406)	—	—	—	—	(406)	—	(406)
End of 2025	2,093	5,891	7,984	248	665	390	418	9,705	5,814	15,519

Years Ended December 31	Natural Gas Billions of Cubic Feet									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed										
End of 2022	2,474	2,628	5,102	64	641	322	241	6,370	3,974	10,344
End of 2023	2,156	2,525	4,681	92	591	305	172	5,841	3,558	9,399
End of 2024	2,186	3,670	5,856	147	642	289	457	7,391	3,189	10,580
End of 2025	1,994	3,379	5,373	123	584	385	413	6,878	3,148	10,026
Undeveloped										
End of 2022	28	2,114	2,142	30	221	4	—	2,397	1,779	4,176
End of 2023	19	2,196	2,215	148	232	7	—	2,602	1,717	4,319
End of 2024	60	2,066	2,126	132	104	7	11	2,380	2,681	5,061
End of 2025	99	2,512	2,611	125	81	5	5	2,827	2,666	5,493

**All Equity Affiliate reserves are located in our Asia Pacific/Middle East Region.*

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed in production operations. Quantities consumed in production operations are not significant in the periods presented. The value of net production consumed in operations is not reflected in net revenues and production expenses, nor do the volumes impact the respective per unit metrics.

Reserve volumes include natural gas to be consumed in operations of 2,211 BCF, 2,285 BCF and 2,263 BCF, as of December 31, 2025, 2024 and 2023, respectively. These volumes are not included in the calculation of our Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities.

Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Notable changes in proved natural gas reserves in the three years ended December 31, 2025, included:

- *Revisions*: In 2025, upward revisions in Lower 48 were due to additional development drilling of 1,288 BCF, technical revisions of 335 BCF, and 108 BCF due to lower operating costs, partly offset by downward revisions of 487 BCF for changes in development plans, and 77 BCF due to lower prices. In the consolidated operations in Asia Pacific/Middle East, upward revisions in Malaysia were 120 BCF, where upward revisions of 113 BCF resulted from the extension of the Kebabangan Cluster (KBBC) PSC and additional agreements, and improved prices of 7 BCF. An additional 3 BCF of upward revisions in China were due to technical revisions. Upward technical revisions in Europe of 45 BCF were in Norway. Downward revisions in Alaska included 59 BCF due to price and 38 BCF to be consumed in operations, offset by development plan updates of 13 BCF and upward technical revisions of 8 BCF. Downward revisions in Canada were due to changes in development plans of 15 BCF and technical revisions of 14 BCF. Our equity affiliates in Australia had upward technical revisions of 319 BCF.

  In 2024, upward revisions in Lower 48 were due to were due to additional development drilling of 841 BCF, technical revisions of 113 BCF, partly offset by downward revisions of 422 BCF for changes in development plans, 127 BCF due to lower prices and 49 BCF due to increasing operating costs. Upward revisions in Alaska of 68 BCF were due to updated total North Slope development phasing, as future production of gas is dependent on the Trans-Alaska Pipeline System minimum flow limit, which will be reached later than previously premised. Further upward revisions in Alaska included 28 BCF from revised development plans and 24 BCF to be consumed in operations. Offsetting downward revisions from technical revisions and costs were 18 BCF. In Europe, technical revisions contributed 64 BCF of upward revisions, offset by 17 BCF of development plan changes. In our equity affiliates, downward revisions were due to lower prices of 81 BCF, partially offset by positive technical revisions of 55 BCF.

  In 2023, upward revisions in Lower 48 were due to additional development drilling in the unconventional plays of 502 BCF, technical revisions of 268 BCF, partly offset by lower prices of 211 BCF and development plan downward revisions of 38 BCF. In Europe, technical revisions contributed 64 BCF and development drilling of 14 BCF, partially offset by lower prices of 5 BCF. In Canada, upward revisions were driven by technical revisions of 37 BCF, partially offset by lower prices of 10 BCF. In Alaska, where future production is constrained by the Trans-Alaska Pipeline System minimum flow limit, updated total North Slope development phasing indicated that the flow limit will be reached earlier than previously premised, resulting in downward revisions of 121 BCF. Further downward revisions in Alaska included 72 BCF from operating efficiencies resulting in less gas to be consumed in operations, 22 BCF due to lower prices, 14 BCF from cost escalation, and 14 BCF due to technical revisions. Downward revisions in Africa of 57 BCF due to infrastructure constraints and sales demand revisions. In our equity affiliates, downward revisions were due to lower prices of 288 BCF, offset by upward technical revisions of 198 BCF.

- *Purchases*: In 2024, our acquisition of Marathon Oil resulted in purchases for Lower 48, as well as for Africa, representing reserves in Equatorial Guinea. Purchases in Alaska represent the acquisition of additional interest in the Kuparuk River and Prudhoe Bay units.

- *Extensions and discoveries*: In 2025, extensions and discoveries in Lower 48 were primarily within unconventional plays in the Permian Basin. Canada extensions and discoveries were in Montney. Extensions and discoveries in our equity affiliates were in Australia.

  In 2024, extensions and discoveries in Lower 48 were primarily within unconventional plays in the Permian Basin. Canada extensions and discoveries were in Montney. Extensions and discoveries in our equity affiliates were in the Middle East and Australia.

  In 2023, extensions and discoveries in Lower 48 were primarily within unconventional plays in the Permian Basin. Canada extensions and discoveries were in Montney. Extensions and discoveries in our equity affiliates were in Australia.

- *Sales*: In 2025, Lower 48 sales represent noncore asset dispositions in the Anadarko Basin of 344 BCF, offshore US assets of 15 BCF, and other assets of 47 BCF, primarily in the Permian Basin.

  In 2023, Lower 48 sales represent the disposition of noncore assets.

Years Ended December 31	Bitumen	
	Millions of Barrels	
	Canada	Total*
Developed and Undeveloped		
End of 2022	216	216
Revisions	15	15
Improved recovery	—	—
Purchases	209	209
Extensions and discoveries	—	—
Production	(30)	(30)
Sales	—	—
End of 2023	410	410
Revisions	118	118
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	—
Production	(45)	(45)
Sales	—	—
End of 2024	483	483
Revisions	(32)	(32)
Improved recovery	—	—
Purchases	—	—
Extensions and discoveries	—	—
Production	(49)	(49)
Sales	—	—
End of 2025	402	402

Years Ended December 31	Bitumen	
	Millions of Barrels	
	Canada	Total*
Developed		
End of 2022	127	127
End of 2023	293	293
End of 2024	230	230
End of 2025	234	234
Undeveloped		
End of 2022	89	89
End of 2023	117	117
End of 2024	253	253
End of 2025	168	168

**There are no Bitumen reserves associated with our Equity Affiliates.*

Notable changes in proved bitumen reserves in the three years ended December 31, 2025, included:

- *Revisions*: In 2025, downward revisions of 67 million barrels due to changes in development timing were partially offset by upward technical revisions of 18 million barrels and an upward revision of 17 million barrels due to the impact of price on variable royalties.

  In 2024, upward revisions of 125 million barrels due to changes in development timing was partially offset by downward revisions due to price of 7 million barrels.

  In 2023, the upward revision of 15 million barrels is primarily due to the impact of price on variable royalties.

- *Purchases:* In 2023, purchases in Canada were a result of the acquisition of the remaining 50 percent working interest in Surmont.

Years Ended December 31	Total Proved Reserves									
	Millions of Barrels of Oil Equivalent									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed and Undeveloped										
End of 2022	1,450	3,048	4,498	245	331	173	250	5,497	1,102	6,599
Revisions	(98)	332	234	20	12	9	1	276	(14)	262
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	4	4	209	—	—	—	213	—	213
Extensions and discoveries	219	94	313	45	3	20	—	381	10	391
Production	(83)	(387)	(470)	(38)	(43)	(26)	(19)	(596)	(82)	(678)
Sales	—	(29)	(29)	—	—	—	—	(29)	—	(29)
End of 2023	1,488	3,062	4,550	481	303	176	232	5,742	1,016	6,758
Revisions	25	367	392	127	3	16	52	590	(6)	584
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	32	768	800	—	—	—	91	891	—	891
Extensions and discoveries	14	59	73	23	—	—	—	96	220	316
Production	(81)	(413)	(494)	(60)	(48)	(26)	(21)	(649)	(83)	(732)
Sales	—	(5)	(5)	—	—	—	—	(5)	—	(5)
End of 2024	1,478	3,838	5,316	571	258	166	354	6,665	1,147	7,812
Revisions	(21)	613	592	(43)	8	35	21	613	54	667
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	46	129	175	14	—	—	—	189	11	200
Production	(81)	(540)	(621)	(66)	(45)	(26)	(38)	(796)	(81)	(877)
Sales	—	(165)	(165)	—	—	—	—	(165)	—	(165)
End of 2025	1,422	3,875	5,297	476	221	175	337	6,506	1,131	7,637

Years Ended December 31	Total Proved Reserves									
	Millions of Barrels of Oil Equivalent									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
Developed										
End of 2022	1,357	1,676	3,033	147	240	155	231	3,806	751	4,557
End of 2023	1,222	1,639	2,861	320	216	142	210	3,749	675	4,424
End of 2024	1,202	2,387	3,589	272	215	136	297	4,509	606	5,115
End of 2025	1,129	2,198	3,327	270	193	155	294	4,239	591	4,830
Undeveloped										
End of 2022	93	1,372	1,465	98	91	18	19	1,691	351	2,042
End of 2023	266	1,423	1,689	161	87	34	22	1,993	341	2,334
End of 2024	276	1,451	1,727	299	43	30	57	2,156	541	2,697
End of 2025	293	1,677	1,970	206	28	20	43	2,267	540	2,807

**All Equity Affiliate reserves are located in our Asia Pacific/Middle East Region.*

Natural gas reserves are converted to BOE based on a 6:1 ratio: six MCF of natural gas converts to one BOE.

Proved Undeveloped Reserves

The following table shows changes in total proved undeveloped reserves for 2025:

	Proved Undeveloped Reserves
	Millions of Barrels of Oil Equivalent
End of 2024	2,697
Revisions	554
Improved recovery	—
Purchases	—
Extensions and discoveries	159
Sales	(3)
Transfers to Proved Developed	(600)
End of 2025	2,807

Upward revisions of 554 MMBOE were predominately driven by progression of development plans of 635 MMBOE in the Lower 48 unconventional plays (including development plan updates in 2025 following the acquisition of Marathon Oil in late 2024), Alaska, and Libya, including 61 MMBOE due to extension of economic limit resulting from new development. This is partly offset by changes in development plans, primarily in Canada.

Extensions and discoveries were largely driven by the continued development planned in Lower 48. The remaining extensions and discoveries were driven by the continued development planned in the other geographic regions, including Alaska, Canada, and Australia.

Transfers to proved developed reserves were driven by the ongoing development of our assets. Approximately 76 percent of the transfers were from the development of our Lower 48 unconventional plays. The remainder of transfers were from development across the other geographic regions.

At December 31, 2025, our PUDs represented 37 percent of total proved reserves, compared with 35 percent at December 31, 2024. Costs incurred for the year ended December 31, 2025 relating to the development of PUDs were $10.3 billion. A portion of our costs incurred each year relates to development projects where the PUDs will be converted to proved developed reserves in future years.

At the end of 2025, approximately 89 percent of total PUDs were under development or scheduled for development within five years of initial disclosure, including all of our Lower 48 PUDs. The PUDs to be developed beyond five years are in the Willow project in Alaska, a development that is currently underway with production anticipated in 2029 due to its large scale and remote location, as well as in major development areas which are currently producing and located in Canada and Australia.

Results of Operations

The company's results of operations from oil and gas activities for the years 2025, 2024 and 2023 are shown in the following tables. Non-oil and gas activities, such as pipeline and marine operations, LNG operations, crude oil and gas marketing activities, and the profit element of transportation operations in which we have an ownership interest are excluded. Additional information about selected line items within the results of operations tables is shown below:

- Sales include sales to unaffiliated entities attributable primarily to the company's net working interests and royalty interests. Sales are net of fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are not consolidated.
- Transportation costs reflect fees to transport our produced hydrocarbons beyond the production function to a final delivery point using transportation operations which are consolidated.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.
- Production costs include costs incurred to operate and maintain wells, related equipment and facilities used in the production of petroleum liquids and natural gas.
- Taxes other than income taxes include production, property and other non-income taxes.
- Depreciation of support equipment is reclassified as applicable.
- Other related expenses include inventory fluctuations, foreign currency transaction gains and losses and other miscellaneous expenses.

Results of Operations

	Millions of Dollars									
Year Ended December 31, 2025	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total Consolidated Operations	Equity Affiliates*
Consolidated operations										
Sales	$ 5,048	21,553	26,601	2,387	3,158	1,601	2,182	—	35,929	730
Transfers	5	—	5	—	—	—	—	—	5	2,716
Transportation costs	(787)	—	(787)	—	—	—	—	—	(787)	—
Other revenues	1	505	506	20	33	39	181	15	794	13
Total revenues	4,267	22,058	26,325	2,407	3,191	1,640	2,363	15	35,941	3,459
Production costs excluding taxes	1,485	5,856	7,341	832	613	358	296	1	9,441	540
Taxes other than income taxes	376	1,500	1,876	27	42	56	4	—	2,005	1,007
Exploration expenses	32	174	206	24	32	117	24	—	403	—
Depreciation, depletion and amortization	1,239	8,092	9,331	511	676	459	231	—	11,208	447
Impairments	1	26	27	(1)	—	—	—	—	26	—
Other related expenses	59	70	129	18	19	(40)	12	16	154	(4)
Accretion	108	123	231	18	72	31	—	—	352	27
	967	6,217	7,184	978	1,737	659	1,796	(2)	12,352	1,442
Income tax provision (benefit)	248	1,293	1,541	233	1,354	243	1,447	1	4,819	443
Results of operations	$ 719	4,924	5,643	745	383	416	349	(3)	7,533	999

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region.*

Year Ended December 31,2024	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total Consolidated Operations	Equity Affiliates*
	Millions of Dollars									
Consolidated operations										
Sales	$ 5,574	19,028	24,602	2,567	3,469	1,847	1,488	—	33,973	917
Transfers	6	—	6	—	—	—	—	—	6	3,343
Transportation costs	(709)	—	(709)	—	—	—	—	—	(709)	—
Other revenues	—	108	108	(34)	(69)	3	117	13	138	18
Total revenues	4,871	19,136	24,007	2,533	3,400	1,850	1,605	13	33,408	4,278
Production costs excluding taxes	1,330	4,691	6,021	902	506	350	120	—	7,899	543
Taxes other than income taxes	410	1,372	1,782	31	36	108	4	—	1,961	1,181
Exploration expenses	74	85	159	80	68	40	8	1	356	—
Depreciation, depletion and amortization	1,175	6,422	7,597	594	689	424	67	—	9,371	484
Impairments	32	42	74	4	2	—	—	—	80	—
Other related expenses	(36)	49	13	(52)	(68)	—	5	14	(88)	(8)
Accretion	106	79	185	18	68	28	—	—	299	19
	1,780	6,396	8,176	956	2,099	900	1,401	(2)	13,530	2,059
Income tax provision (benefit)	461	1,407	1,868	224	1,539	222	1,306	(1)	5,158	623
Results of operations	$ 1,319	4,989	6,308	732	560	678	95	(1)	8,372	1,436

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region.*

Year Ended December 31,2023	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total Consolidated Operations	Equity Affiliates*
	Millions of Dollars									
Consolidated operations										
Sales	$ 5,918	18,976	24,894	1,517	3,449	1,914	1,447	—	33,221	822
Transfers	5	—	5	—	—	—	—	—	5	3,429
Transportation costs	(611)	—	(611)	—	—	—	—	—	(611)	—
Other revenues	(4)	142	138	(1)	3	(1)	181	3	323	14
Total revenues	5,308	19,118	24,426	1,516	3,452	1,913	1,628	3	32,938	4,265
Production costs excluding taxes	1,242	4,175	5,417	602	499	348	74	1	6,941	493
Taxes other than income taxes	442	1,347	1,789	26	35	115	3	—	1,968	1,208
Exploration expenses	72	153	225	49	73	44	4	3	398	—
Depreciation, depletion and amortization	938	5,702	6,640	374	532	454	50	—	8,050	390
Impairments	—	7	7	6	—	—	—	—	13	—
Other related expenses	71	42	113	60	(24)	17	3	12	181	(8)
Accretion	94	65	159	12	61	27	—	—	259	30
	2,449	7,627	10,076	387	2,276	908	1,494	(13)	15,128	2,152
Income tax provision (benefit)	640	1,667	2,307	5	1,704	66	1,375	—	5,457	658
Results of operations	$ 1,809	5,960	7,769	382	572	842	119	(13)	9,671	1,494

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region.*

Statistics

Net Production	2025	2024	2023
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**177**	173	173
Lower 48	**749**	602	569
United States	**926**	775	742
Canada	**17**	17	9
Europe	**63**	69	64
Asia Pacific	**59**	59	60
Africa	**68**	49	48
Total consolidated operations	**1,133**	969	923
Equity affiliates—Asia Pacific/Middle East	**12**	13	13
Total company	**1,145**	982	936
*Delaware Basin Area (Lower 48)**	***321***	*301*	*274*
Natural Gas Liquids			
Consolidated operations			
Alaska	**15**	15	16
Lower 48	**382**	279	256
United States	**397**	294	272
Canada	**6**	6	3
Europe	**3**	4	4
Africa	**5**	—	—
Total consolidated operations	**411**	304	279
Equity affiliates—Asia Pacific/Middle East	**8**	8	8
Total company	**419**	312	287
*Delaware Basin Area (Lower 48)**	***171***	*144*	*135*
Bitumen			
Consolidated operations—Canada	**133**	122	81
Total company	**133**	122	81
Natural Gas	Millions of Cubic Feet Daily		
Consolidated operations			
Alaska	**41**	39	38
Lower 48	**2,119**	1,625	1,457
United States	**2,160**	1,664	1,495
Canada	**125**	115	65
Europe	**330**	329	279
Asia Pacific	**63**	50	48
Africa	**181**	42	29
Total consolidated operations	**2,859**	2,200	1,916
Equity affiliates—Asia Pacific/Middle East	**1,206**	1,233	1,219
Total company	**4,065**	3,433	3,135
*Delaware Basin Area (Lower 48)**	***1,011***	*884*	*768*

**At year-end 2025, 2024 and 2023, the Delaware Basin Area in Lower 48 contained more than 15 percent of our total proved reserves.*

Average Sales Prices	**2025**	2024	2023
Crude Oil Per Barrel			
Consolidated operations			
Alaska*	$ **60.59**	71.32	74.46
Lower 48	**63.18**	74.17	76.19
United States	**62.65**	73.49	75.75
Canada	**55.35**	64.47	66.19
Europe	**70.52**	81.09	84.56
Asia Pacific	**71.05**	82.42	84.79
Africa	**67.45**	80.65	83.07
Total international	**68.44**	79.97	83.33
Total consolidated operations	**63.70**	74.76	77.19
Equity affiliates—Asia Pacific/Middle East	**68.94**	76.76	78.45
Total operations	**63.75**	74.78	77.21
Natural Gas Liquids Per Barrel			
Consolidated operations			
Lower 48	$ **20.64**	22.02	21.73
United States	**20.64**	22.02	21.73
Canada	**22.54**	29.59	26.13
Europe	**41.39**	45.50	41.13
Africa	**1.00**	—	—
Total international	**19.23**	33.60	34.56
Total consolidated operations	**20.59**	22.43	22.12
Equity affiliates—Asia Pacific/Middle East	**46.20**	51.53	47.09
Total operations	**21.07**	23.19	22.82
Bitumen Per Barrel			
Consolidated operations—Canada	$ **40.74**	47.92	42.15
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	$ **3.81**	3.90	4.47
Lower 48	**1.74**	0.87	2.12
United States	**1.74**	0.88	2.13
Canada**	**1.02**	0.54	1.80
Europe	**12.08**	11.11	13.33
Asia Pacific	**3.59**	3.74	3.95
Africa	**8.58**	7.32	6.49
Total international	**8.44**	7.87	10.01
Total consolidated operations	**3.40**	2.61	3.89
Equity affiliates—Asia Pacific/Middle East	**6.83**	8.22	8.46
Total operations	**4.44**	4.69	5.69

**Average sales prices for Alaska crude oil above reflects a reduction for transportation costs in which we have an ownership interest that are incurred subsequent to the terminal point of the production function. Accordingly, the average sales prices differ from those discussed in Item 7 of Management's Discussion and Analysis of Financial Condition and Results of Operations.*
***Average sales prices include unutilized transportation costs.*

		2025	2024	2023
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**20.44**	18.73	17.45
Lower 48		**10.81**	11.13	10.72
United States		**11.95**	12.22	11.76
Canada		**12.88**	15.03	15.86
Europe		**13.88**	10.80	11.89
Asia Pacific		**14.01**	14.27	14.02
Africa		**7.87**	5.85	3.83
Total international		**12.22**	12.36	12.28
Total consolidated operations		**12.01**	12.26	11.87
Equity affiliates—Asia Pacific/Middle East		**6.69**	6.56	6.03
Average Production Costs Per Barrel—Bitumen				
Consolidated operations—Canada	$	**11.63**	15.19	14.42
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**5.18**	5.77	6.21
Lower 48		**2.77**	3.25	3.46
United States		**3.05**	3.62	3.88
Canada		**0.42**	0.52	0.68
Europe		**0.95**	0.77	0.83
Asia Pacific		**2.19**	4.40	4.63
Africa		**0.11**	0.20	0.16
Total international		**0.75**	1.18	1.44
Total consolidated operations		**2.55**	3.04	3.37
Equity affiliates—Asia Pacific/Middle East		**12.48**	14.28	14.77
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**17.06**	16.55	13.18
Lower 48		**14.94**	15.23	14.64
United States		**15.19**	15.42	14.42
Canada		**7.91**	9.90	9.85
Europe		**15.31**	14.71	12.67
Asia Pacific		**17.96**	17.29	18.29
Africa		**6.14**	3.27	2.58
Total international		**10.92**	11.68	11.36
Total consolidated operations		**14.26**	14.54	13.77
Equity affiliates—Asia Pacific/Middle East		**5.54**	5.85	4.77

**Includes bitumen.*

Development and Exploration Activities

The following two tables summarize our net interest in productive and dry exploratory and development wells in the years ended December 31, 2025, 2024 and 2023. A “development well” is a well drilled within the proved area of a reservoir to the depth of a stratigraphic horizon known to be productive. An “exploratory well” is a well drilled to find and produce crude oil or natural gas in an unknown field or a new reservoir within a proven field. Exploratory wells also include wells drilled in areas near or offsetting current production, or in areas where well density or production history have not achieved statistical certainty of results. Excluded from the exploratory well count are stratigraphic-type exploratory wells, primarily relating to oil sands delineation wells located in Canada and CBM test wells located in Asia Pacific/Middle East.

Net Wells Completed

	Productive			Dry		
	2025	2024	2023	**2025**	2024	2023
Exploratory						
Consolidated operations						
Alaska	**—**	—	—	**—**	—	2
Lower 48	**31**	39	38	**—**	—	2
United States	**31**	39	38	**—**	—	4
Canada	**4**	7	6	**—**	—	—
Europe	**—**	—	—	*****	*	*
Asia Pacific/Middle East	*****	*	—	**4**	—	—
Africa	**—**	—	—	**—**	1	—
Total consolidated operations	**35**	46	44	**4**	1	4
Equity affiliates						
Asia Pacific/Middle East	**6**	2	3	**—**	—	*
Total equity affiliates	**6**	2	3	**—**	—	*
Development						
Consolidated operations						
Alaska	**14**	13	11	**—**	—	—
Lower 48	**657**	507	494	**—**	—	—
United States	**671**	520	505	**—**	—	—
Canada	**40**	38	21	**—**	—	—
Europe	**4**	8	4	**—**	—	—
Asia Pacific/Middle East	**24**	23	20	**—**	—	—
Africa	**11**	5	4	*****	—	—
Total consolidated operations	**750**	594	554	**—**	—	—
Equity affiliates						
Asia Pacific/Middle East	**87**	54	45	**—**	—	—
Total equity affiliates	**87**	54	45	**—**	—	—

**Our total proportionate interest was less than one.*

The table below represents the status of our wells drilling at December 31, 2025, and includes wells in the process of drilling or in active completion. It also represents gross and net productive wells, including producing wells and wells capable of production at December 31, 2025.

Wells at December 31, 2025

			Productive			
	In Progress		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	2	2	1,547	940	—	—
Lower 48	717	417	19,692	9,900	3,921	2,633
United States	719	419	21,239	10,840	3,921	2,633
Canada	59	59	227	227	178	178
Europe	10	3	513	83	70	4
Asia Pacific/Middle East	16	8	536	254	6	2
Africa	20	5	972	198	27	13
Total consolidated operations	824	494	23,487	11,602	4,202	2,830
Equity affiliates						
Asia Pacific/Middle East	242	35	—	—	5,924	1,709
Total equity affiliates	242	35	—	—	5,924	1,709

Acreage at December 31, 2025

	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	741	566	1,038	1,012
Lower 48	3,938	2,756	10,797	8,293
United States	4,679	3,322	11,835	9,305
Canada	316	293	3,387	1,998
Europe	451	58	347	155
Asia Pacific/Middle East	422	152	7,596	4,996
Africa	440	140	12,545	2,561
Total consolidated operations	6,308	3,965	35,710	19,015
Equity affiliates				
Asia Pacific/Middle East	1,160	342	4,003	1,039
Total equity affiliates	1,160	342	4,003	1,039

Costs Incurred

Year Ended December 31	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total Consolidated Operations	Equity Affiliates*
2025										
Consolidated operations										
Unproved property acquisition	$ —	215	215	—	—	—	—	—	215	—
Proved property acquisition	5	42	47	—	—	—	—	—	47	—
	5	257	262	—	—	—	—	—	262	—
Exploration	42	573	615	61	113	113	26	—	928	9
Development	3,549	6,102	9,651	574	428	282	239	—	11,174	439
	$ 3,596	6,932	10,528	635	541	395	265	—	12,364	448
2024										
Consolidated operations										
Unproved property acquisition	$ —	10,985	10,985	—	—	—	—	—	10,985	—
Proved property acquisition	297	12,118	12,415	(46)	—	—	1,100	—	13,469	—
	297	23,103	23,400	(46)	—	—	1,100	—	24,454	—
Exploration	98	548	646	239	49	46	7	1	988	18
Development	2,808	6,301	9,109	390	598	354	91	—	10,542	323
	$ 3,203	29,952	33,155	583	647	400	1,198	1	35,984	341
2023										
Consolidated operations										
Unproved property acquisition	$ —	157	157	156	—	—	—	—	313	—
Proved property acquisition	—	106	106	2,973	—	—	—	—	3,079	—
	—	263	263	3,129	—	—	—	—	3,392	—
Exploration	67	396	463	144	45	49	4	3	708	46
Development	1,884	6,266	8,150	367	843	383	38	—	9,781	416
	$ 1,951	6,925	8,876	3,640	888	432	42	3	13,881	462

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region.*

Capitalized Costs

At December 31	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Other Areas	Total Consolidated Operations	Equity Affiliates*
2025										
Consolidated operations										
Proved property	$ 32,822	93,970	126,792	12,060	15,047	11,561	2,509	—	167,969	12,121
Unproved property	117	9,102	9,219	1,299	129	76	99	—	10,822	2,135
	32,939	103,072	136,011	13,359	15,176	11,637	2,608	—	178,791	14,256
Accumulated depreciation, depletion and amortization	15,150	46,781	61,931	4,332	11,276	9,305	800	—	87,644	9,681
	$ 17,789	56,291	74,080	9,027	3,900	2,332	1,808	—	91,147	4,575
2024										
Consolidated operations										
Proved property	$ 29,435	88,461	117,896	10,904	12,986	11,274	2,304	—	155,364	11,691
Unproved property	107	13,883	13,990	1,256	41	96	97	10	15,490	2,133
	29,542	102,344	131,886	12,160	13,027	11,370	2,401	10	170,854	13,824
Accumulated depreciation, depletion and amortization	13,946	42,089	56,035	3,651	9,412	8,842	575	10	78,525	9,246
	$ 15,596	60,255	75,851	8,509	3,615	2,528	1,826	—	92,329	4,578

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region.*

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices (adjusted only for existing contractual terms) and end-of-year costs, appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves and the timing and amount of future development costs, including dismantlement, and future production costs, including taxes other than income taxes.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
2025										
Future cash inflows	$ 66,071	148,328	214,399	18,409	14,974	8,965	22,224	278,971	44,287	323,258
Less:										
Future production costs	36,032	69,324	105,356	7,854	5,290	3,726	2,466	124,692	27,353	152,045
Future development costs	13,540	21,994	35,534	1,628	3,697	1,359	576	42,794	3,175	45,969
Future income tax provisions	3,660	10,185	13,845	1,185	4,649	950	17,079	37,708	3,901	41,609
Future net cash flows	12,839	46,825	59,664	7,742	1,338	2,930	2,103	73,777	9,858	83,635
10 percent annual discount	5,400	14,372	19,772	2,607	(32)	914	570	23,831	3,842	27,673
Discounted future net cash flows	$ 7,439	32,453	39,892	5,135	1,370	2,016	1,533	49,946	6,016	55,962

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region. Total Discounted future net cash flows for Asia Pacific/Middle East was $8,032.*

	Millions of Dollars									
	Alaska	Lower 48**	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
2024										
Future cash inflows	$ 79,396	164,264	243,660	24,685	18,148	10,405	26,592	323,490	51,975	375,465
Less:										
Future production costs	39,861	73,663	113,524	9,433	5,924	4,189	2,678	135,748	29,807	165,555
Future development costs	12,766	21,143	33,909	2,370	3,611	1,586	693	42,169	3,234	45,403
Future income tax provisions	5,664	13,098	18,762	1,886	6,680	1,131	20,750	49,209	5,630	54,839
Future net cash flows	21,105	56,360	77,465	10,996	1,933	3,499	2,471	96,364	13,304	109,668
10 percent annual discount	9,742	17,667	27,409	4,217	94	1,087	828	33,635	5,170	38,805
Discounted future net cash flows	$ 11,363	38,693	50,056	6,779	1,839	2,412	1,643	62,729	8,134	70,863

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region. Total Discounted future net cash flows for Asia Pacific/Middle East was $10,546.*

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Middle East	Africa	Total Consolidated Operations	Equity Affiliates*	Total
2023										
Future cash inflows	$ 83,793	141,307	225,100	19,937	23,569	11,322	21,562	301,490	51,887	353,377
Less:										
Future production costs	39,069	57,303	96,372	8,699	6,576	4,586	1,008	117,241	28,579	145,820
Future development costs	13,685	21,391	35,076	2,058	3,802	1,458	400	42,794	2,299	45,093
Future income tax provisions	7,386	12,451	19,837	880	10,140	1,316	18,687	50,860	5,647	56,507
Future net cash flows	23,653	50,162	73,815	8,300	3,051	3,962	1,467	90,595	15,362	105,957
10 percent annual discount	11,522	16,850	28,372	2,723	432	1,257	570	33,354	5,543	38,897
Discounted future net cash flows	$ 12,131	33,312	45,443	5,577	2,619	2,705	897	57,241	9,819	67,060

**All Equity Affiliate activity is located in our Asia Pacific/Middle East Region. Total Discounted future net cash flows for Asia Pacific/Middle East was $12,524.*

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2025	2024	2023	**2025**	2024	2023	**2025**	2024	2023
Discounted future net cash flows at the beginning of the year	**$ 62,729**	$ 57,241	85,720	**$ 8,134**	9,819	13,272	**$ 70,863**	67,060	98,992
Changes during the year									
Revenues less production costs for the year	**(23,701)**	(23,410)	(23,706)	**(1,899)**	(2,536)	(2,550)	**(25,600)**	(25,946)	(26,256)
Net change in prices, and production costs	**(16,493)**	(10,025)	(51,887)	**(3,081)**	(941)	(4,519)	**(19,574)**	(10,966)	(56,406)
Extensions, discoveries and improved recovery, less estimated future costs	**(1,959)**	(1,015)	1,751	**(95)**	507	118	**(2,054)**	(508)	1,869
Development costs for the year	**11,110**	10,197	9,129	**458**	402	326	**11,568**	10,599	9,455
Changes in estimated future development costs	**(5,229)**	(3,512)	(6,754)	**(94)**	(274)	(150)	**(5,323)**	(3,786)	(6,904)
Purchases of reserves in place, less estimated future costs	**—**	11,068	3,024	**—**	—	—	**—**	11,068	3,024
Sales of reserves in place, less estimated future costs	**(1,161)**	(113)	(446)	**—**	—	—	**(1,161)**	(113)	(446)
Revisions of previous quantity estimates	**9,242**	14,175	9,047	**491**	23	492	**9,733**	14,198	9,539
Accretion of discount	**8,553**	8,137	12,414	**1,049**	1,199	1,635	**9,602**	9,336	14,049
Net change in income taxes	**6,855**	(14)	18,949	**1,053**	(65)	1,195	**7,908**	(79)	20,144
Total changes	**(12,783)**	5,488	(28,479)	**(2,118)**	(1,685)	(3,453)	**(14,901)**	3,803	(31,932)
Discounted future net cash flows at year end	**$ 49,946**	$ 62,729	57,241	**$ 6,016**	8,134	9,819	**$ 55,962**	70,863	67,060

- The net change in prices and production costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price and production cost, discounted at 10 percent.

- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- Revisions of previous quantity estimates are calculated using production forecast changes for the year, including changes in the timing of production, multiplied by the 12-month average sales prices, less future estimated costs, discounted at 10 percent.

- The accretion of discount is 10 percent of the prior year’s discounted future cash inflows, less future production and development costs.

- The net change in income taxes is the annual change in the discounted future income tax provisions.

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

None.

Item 9A. Controls and Procedures

We maintain disclosure controls and procedures designed to ensure information required to be disclosed in reports we file or submit under the Securities Exchange Act of 1934, as amended (the Act), is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. As of December 31, 2025, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Chief Financial Officer and Executive Vice President, Strategy and Commercial (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Act, of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Chief Financial Officer and Executive Vice President, Strategy and Commercial concluded our disclosure controls and procedures were operating effectively as of December 31, 2025.

In the first quarter of 2025, we completed the final phase of a multi-year implementation of an updated global enterprise resource planning system. As a result, we made corresponding changes to our business processes and information systems, updating applicable internal controls over financial reporting where necessary.

There have been no other changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting
This report is included in Item 8 on page *67* and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm
This report is included in Item 8 on page *68* and is incorporated herein by reference.

Item 9B. Other Information

Insider Trading Arrangements
During the three-month period ended December 31, 2025, no officer or director of the company adopted or terminated any Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our executive officers appears in Part I of this report on page *28*.

Code of Business Ethics and Conduct for Directors and Employees
We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the "Corporate Governance" section of our internet website at *www.conocophillips.com* (within the Investors>Corporate Governance section). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the "Corporate Governance" section of our internet website.

Insider Trading Policies and Procedures
We have adopted insider trading policies and procedures governing the purchase, sale and/or other dispositions of our securities by directors, officers and other personnel employed by us or any of our subsidiaries. All personnel are responsible for ensuring their "Related Parties" (as defined in the policies) comply as well. We have an additional insider trading policy that applies only to our directors, Section 16 officers and other designated officers and employees. We believe our insider trading policies are reasonably designed to promote compliance with insider trading laws, rules and regulations, the listing standards of the NYSE and Section 16 reporting requirements, as applicable.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2026 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2026, and is incorporated herein by reference.*

Item 11. Executive Compensation

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2026 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2026, and is incorporated herein by reference.*

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

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2026 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2026, and is incorporated herein by reference.*

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

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2026 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2026, and is incorporated herein by reference.*

Item 14. Principal Accounting Fees and Services

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2026 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2026, and is incorporated herein by reference.*

* *Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2026 Proxy Statement are not deemed to be a part of this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.*

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial Statements and Supplementary Data
The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page *66*, are filed as part of this annual report.

2. Financial Statement Schedules
All financial statement schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages *154 through 157*, are filed as part of this annual report.

ConocoPhillips

Index to Exhibits

Exhibit No.	Description	Incorporated by Reference Exhibit	Form	File No.
2.1	Separation and Distribution Agreement Between ConocoPhillips and Phillips 66, dated April 26, 2012.	2.1	8-K	001-32395
2.2	Agreement and Plan of Merger, dated as of May 28, 2024, by and among ConocoPhillips, Puma Merger Sub Corp, and Marathon Oil Corporation.	2.1	8-K	001-32395
3.1	Amended and Restated Certificate of Incorporation of ConocoPhillips.	3.1	10-Q	001-32395
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips.	3.2	8-K	000-49987
3.3	Second Amended and Restated Bylaws, dated May 16, 2023.	3.1	8-K	001-32395
3.4	Corrected Restated Certificate of Incorporation of ConocoPhillips Company, dated as of April 28, 2022.	3.3	S-4	001-32395
3.5	Bylaws of ConocoPhillips Company.	3.5	S-3	001-32395
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.			
4.1	Description of Securities of the Registrant.	4.1	10-K	001-32395
10.1	Indemnification and Release Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.1	8-K	001-32395
10.2	Intellectual Property Assignment and License Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.2	8-K	001-32395
10.3	Tax Sharing Agreement between ConocoPhillips and Phillips 66, dated April 26, 2012.	10.3	8-K	001-32395
10.4	Employee Matters Agreement between ConocoPhillips and Phillips 66, dated April 12, 2012.	10.4	8-K	001-32395
10.5.1	Phillips Petroleum Company Grantor Trust Agreement, dated June 1, 1998.	10.17.3	10-K	001-32395
10.5.2	First Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated May 3, 1999.	10.17.4	10-K	001-32395
10.5.3	Second Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated January 15, 2002.	10.17.5	10-K	001-32395
10.5.4	Third Amendment to the Trust Agreement under the Phillips Petroleum Company Grantor Trust Agreement, dated October 5, 2006.	10.17.6	10-K	001-32395
10.5.5	Fourth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 1, 2012.	10.17.7	10-K	001-32395
10.5.6	Fifth Amendment to the Trust Agreement under the ConocoPhillips Company Grantor Trust Agreement, dated May 20, 2015.	10.17.8	10-K	001-32395
10.6.1	Successor Trustee Agreement of the Deferred Compensation Trust Agreement for Non-Employee Directors of ConocoPhillips dated July 31, 2020.	10.1	10-Q	001-32395
10.6.2	First Amendment to the Successor Trust Agreement of the Deferred Compensation Trust Agreement for Non-Employee Directors of ConocoPhillips, dated August 4, 2020.	10.2	10-Q	001-32395
10.7	Omnibus Securities Plan of Phillips Petroleum Company.	10.19	10-K	004-49987

10.8	2002 Omnibus Securities Plan of Phillips Petroleum Company.	10.26	10-K	000-49987
10.9.1	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	000-49987
10.9.2	Form of Performance Share Unit Award Agreement under the Performance Share Program under the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.27	10-K	001-32395
10.10	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007.	10.30	10-K	001-32395
10.11	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	001-32395
10.12.1	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	Schedule 14A	Proxy	001-32395
10.12.2	Form of Performance Share Unit Agreement under the Restricted Stock Program under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 5, 2013.	10.26.6	10-K	001-32395
10.12.3	Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 18, 2014.	10.1	10-Q	001-32395
10.13.1	2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.1	8-K	001-32395
10.13.2	Form of Key Employee Award Agreement, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 16, 2016.	10.26.12	10-K	001-32395
10.13.3	Form of Performance Share Unit Award Terms and Conditions for Performance Period 18, as part of the ConocoPhillips Performance Share Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2018.	10.26.24	10-K	001-32395
10.13.4	Form of Key Employee Award Terms and Conditions, as part of the ConocoPhillips Stock Option Program granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 14, 2017.	10.1	10-Q	001-32395
10.13.5	Form of Executive Restricted Stock Unit Award Terms and Conditions, as part of the ConocoPhillips Executive Restricted Stock Unit Program, granted under the 2014 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 11, 2020.	10.1	10-Q	001-32395
10.14.1	2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips	10.1	8-K	001-32395
10.14.2	Form of Performance Share Unit Award Terms and Conditions for Performance Period 24, as part of the ConocoPhillips Performance Share Program granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2024.	10.1	10-Q	001-32395
10.14.3	Form of Executive Restricted Stock Unit Award Terms and Conditions, as part of the ConocoPhillips Executive Restricted Stock Unit Program, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 13, 2024.	10.2	10-Q	001-32395
10.14.4	Form of 2024 Retention Award Terms and Conditions, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.3	10-Q	001-32395
10.14.5	Form of 2024 Inducement Award Terms and Conditions, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.4	10-Q	001-32395
10.14.6	Form of Performance Share Unit Award Terms and Conditions for Performance Period 25, as part of the ConocoPhillips Performance Share Program granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 11, 2025.	10.14.6	10-K	001-32395
10.14.7	Form of Executive Restricted Stock Unit Award Terms and Conditions, as part of the ConocoPhillips Executive Restricted Stock Unit Program, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 11, 2025.	10.14.7	10-K	001-32395

10.14.8	Form of 2025 Cash Retention Award Terms and Conditions, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.1	10-Q	001-32395
10.14.9	Form of 2025 Retention Award Terms and Conditions, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips.	10.2	10-Q	001-32395
10.14.10*	Form of Executive Restricted Stock Unit Award Terms and Conditions, as part of the ConocoPhillips Executive Restricted Stock Unit Program, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 10, 2026.			
10.14.11*	Form of Executive Restricted Stock Unit Award Terms and Conditions, as part of the ConocoPhillips Executive Restricted Stock Unit Program, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 10, 2026.			
10.14.12*	Form of Performance Share Unit Award Terms and Conditions for Performance Period 26, as part of the ConocoPhillips Performance Share Program granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 10, 2026.			
10.14.13*	Form of Performance Share Unit Award Terms and Conditions for Performance Period 26, as part of the ConocoPhillips Performance Share Program granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 10, 2026.			
10.14.14*	Form of Performance Share Unit Award Terms and Conditions for Performance Period 26, as part of the ConocoPhillips Performance Share Program granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, dated February 10, 2026.			
10.15	Amended and Restated ConocoPhillips Key Employee Supplemental Retirement Plan, dated January 1, 2020.	10.10.1	10-K	001-32395
10.16.1	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title I, dated January 1, 2020.	10.11.1	10-K	001-32395
10.16.2*	Amended and Restated Defined Contribution Make-Up Plan of ConocoPhillips—Title II, dated January 1, 2026.			
10.17	Amended and Restated Company Retirement Contribution Make-Up Plan of ConocoPhillips, dated January 1, 2024.	10.17	10-K	001-32395
10.18.1	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title I, dated January 1, 2020.	10.19.1	10-K	001-32395
10.18.2*	Amended and Restated Key Employee Deferred Compensation Plan of ConocoPhillips—Title II, dated January 1, 2026.			
10.19	Amendment and Restatement of ConocoPhillips Key Employee Change in Control Severance Plan, effective December 2, 2021.	10.20.1	10-K	001-32395
10.20.1	Form of Non-Employee Director Restricted Stock Units Terms and Conditions, as part of the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2016.	10.3	10-Q	001-32395
10.20.2	Form of Non-Employee Director Restricted Stock Units Terms and Conditions, granted under the 2023 Omnibus Stock and Performance Incentive Plan of ConocoPhillips and subject to the Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips, dated January 15, 2025.	10.20.2	10-K	001-32395
10.21.1	Amendment and Restatement of Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips dated April 19, 2012.	10.8	10-Q	001-32395
10.21.2	First Amendment to Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips dated December 20, 2019.	10.27	10-K	001-32395
10.22	Amendment and Restatement of ConocoPhillips Executive Severance Plan, dated December 2, 2021.	10.47	10-K	001-32395
10.23	Purchase and Sale Agreement, dated as of September 20, 2021, by and between Shell Enterprises LLC and ConocoPhillips.	10.1	10-Q	001-32395

10.24	Form of Aircraft Time Sharing Agreement by and between certain executives and ConocoPhillips dated June 21, 2021.	10.2	10-Q	001-32395
10.25	Letter agreement with Timothy A. Leach, dated April 28, 2022.	10.1	10-Q	001-32395
10.25.1	Letter Agreement with Timothy A. Leach completed November 4, 2025.	10.1	10-Q	001-32395
10.26	Form of Aircraft Time Sharing Agreement by and between certain executives and ConocoPhillips dated November 14, 2023.	10.29	10-K	001-32395
10.27	Amended and Restated Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips.	10.2	10-Q	001-32395
19*	Insider Trading Policies of ConocoPhillips			
21*	List of Subsidiaries of ConocoPhillips.			
22*	Subsidiary Guarantors of Guaranteed Securities.			
23.1*	Consent of Ernst & Young LLP.			
23.2*	Consent of DeGolyer and MacNaughton.			
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.			
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.			
32**	Certifications pursuant to 18 U.S.C. Section 1350.			
97	ConocoPhillips Clawback Policy effective October 2, 2023.	97.2	10-K	001-32395
99*	Report of DeGolyer and MacNaughton.			
101.INS*	Inline XBRL Instance Document.			
101.SCH*	Inline XBRL Schema Document.			
101.CAL*	Inline XBRL Calculation Linkbase Document.			
101.DEF*	Inline XBRL Definition Linkbase Document.			
101.LAB*	Inline XBRL Labels Linkbase Document.			
101.PRE*	Inline XBRL Presentation Linkbase Document.			
104*	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).			

** Filed herewith.*
***Furnished herewith.*

Signature

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.

CONOCOPHILLIPS

February 17, 2026	*/s/ Ryan M. Lance*
	Ryan M. Lance Chairman of the Board of Directors and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 17, 2026, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ Ryan M. Lance Ryan M. Lance	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ Andrew M. O'Brien Andrew M. O'Brien	Chief Financial Officer and Executive Vice President, Strategy and Commercial (Principal financial officer)
/s/ Kontessa S. Haynes-Welsh Kontessa S. Haynes-Welsh	Vice President, Finance and Controller (Principal accounting officer)

/s/ Dennis V. Arriola Dennis V. Arriola	Director
/s/ Nelda J. Connors Nelda J. Connors	Director
/s/ Gay Huey Evans Gay Huey Evans	Director
/s/ Jeffrey A. Joerres Jeffrey A. Joerres	Director
/s/ Timothy A. Leach Timothy A. Leach	Director
/s/ Kathleen A. McGinty Kathleen A. McGinty	Director
/s/ William H. McRaven William H. McRaven	Director
/s/ Sharmila Mulligan Sharmila Mulligan	Director
/s/ Arjun N. Murti Arjun N. Murti	Director
/s/ Robert A. Niblock Robert A. Niblock	Director
/s/ David T. Seaton David T. Seaton	Director
/s/ R.A. Walker R.A. Walker	Director

Board of Directors

Dennis V. Arriola
Former Chief Executive Officer, Avangrid, Inc.

Nelda J. Connors
Founder and Chief Executive Officer, Pine Grove Holdings

Gay Huey Evans CBE
Former Chairman, London Metal Exchange

Jeffrey A. Joerres
Former Executive Chairman and Chief Executive Officer, ManpowerGroup Inc.

Ryan M. Lance
Chairman and Chief Executive Officer, ConocoPhillips

Timothy A. Leach
Former Chairman and Chief Executive Officer, Concho Resources Inc.

Kathleen A. McGinty
Vice President and Chief Sustainability and External Relations Officer, Johnson Controls International plc

William H. McRaven
Retired U.S. Navy Four-Star Admiral (SEAL)

Sharmila Mulligan
Former Chief Strategy Officer, Alteryx

Arjun N. Murti
Partner, Veriten LLC

Robert A. Niblock
Former Chairman, President and Chief Executive Officer, Lowe's Companies, Inc.

David T. Seaton
Former Chairman and Chief Executive Officer, Fluor Corporation

R.A. Walker
Former Chairman and Chief Executive Officer, Anadarko Petroleum Corporation

Executive Leadership Team

Ryan M. Lance
Chairman and Chief Executive Officer

Heather G. Hrap
Senior Vice President, Human Resources and Real Estate and Facilities Services

Kirk L. Johnson
Executive Vice President, Global Operations and Technical Functions

Andrew D. Lundquist
Senior Vice President, Government Affairs

Andrew M. O'Brien
Chief Financial Officer and Executive Vice President, Strategy and Commercial

Nicholas G. Olds
Executive Vice President, Lower 48 and Global HSE

Kelly B. Rose
Senior Vice President, Legal, General Counsel and Corporate Secretary

Explore ConocoPhillips

Proxy Statement
Published annually and sent to stockholders informing them of when and where our Annual Meeting of Stockholders is taking place and detailing the matters to be voted upon at the meeting.
conocophillips.com/proxy

Sustainability Disclosures
Updated annually to provide details on the company's sustainability governance, risk management, strategy, metrics and targets.
conocophillips.com/sustainability

Upcoming and Past Investor Presentations
Provides notice of future and archived presentations dating back one year, including webcast replays, transcripts and slides.
conocophillips.com/investors

Certain disclosures in this annual report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in the Management's Discussion and Analysis in ConocoPhillips' 2025 Form 10-K should be read in conjunction with such statements.

"ConocoPhillips," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries.

Cautionary Note to U.S. Investors — The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. We use the term "resource" in this annual report, which the SEC's guidelines prohibit us from including in filings with the SEC. U.S. investors are urged to consider closely the oil and gas disclosures in our Form 10-K and other reports and filings with the SEC. Copies are available from the SEC and on the ConocoPhillips website.

Use of Non-GAAP Financial Information — This annual report includes the non-GAAP term "cash from operations" to help facilitate comparisons of company operating performance across periods and with peer companies. Cash from operations is defined as cash provided by operating activities excluding the impact of operating working capital. 2025 cash provided by operating activities was $19.8 billion. Excluding a reduction in operating working capital of $0.1 billion, cash from operations was $19.9 billion.

The non-GAAP term "net debt" is included to provide a measure to compare debt less cash, cash equivalents and short-term investments across periods on a consistent basis. Net debt includes total balance sheet debt less cash, cash equivalents and short-term investments. 2025 short-term and long-term debt was $23.4 billion. Excluding cash, cash equivalents and short-term investments of $7.4 billion, 2025 net debt was $16.0 billion. 2024 short-term and long-term debt was $24.3 billion. Excluding cash, cash equivalents and short-term investments of $6.4 billion, 2024 net debt was $17.9 billion.

ConocoPhillips