

2025
ANNUAL
REPORT



LEGACY IN MOTION

FROM FOUNDATION TO FUTURE

DEAR FELLOW SHAREHOLDER,

We, at Murphy Oil, operate in a sector that is regularly reshaped by external drivers that are largely beyond our ability to predict, much less control. That means that in any one year our priorities, operations, and performance may differ significantly from prior years.

However, the most important driver of our sector stems from one of the most powerful and enduring realities in human history: the positive correlation between people's standards of living and the accessibility of affordable energy. The impact of all other influences pales in comparison.

This reality, which has lasted for thousands of years and is core to human security and happiness, is a brilliant foundation on which we have built Murphy Oil over the last three quarters of a century. It also meshes well with our family-driven foundation, our long-term focus, our diversified operations, and just-right size that enables us to be global, sophisticated, and diversified, but nimble and trusted as well. We call this combination "Legacy in Motion" and it is particularly apt in our current 76th year of incorporation.

The quarterly and other updates we provide during the year can be heavy on detail because we often manage highly technical, sophisticated, and complex projects (a) ranging from the imagination phase to core production mode, (b) based onshore and offshore, and (c) situated in developed and developing countries. So, this annual letter is a good opportunity to step back from that detail and highlight some of the telling results that this Legacy in Motion approach produced in the past year.

In 2025, these included:

- Increasing our average production from 177 thousand to 182 thousand barrels of oil equivalents (BOE) per day
- Reducing our lease operating expenses per BOE by 20 percent from the prior year
- Decreasing our Eagle Ford Shale drilling cost per well by 7 percent year over year
- Drilling the longest laterals in our history in both Eagle Ford Shale and onshore Canada
- Achieving Tupper Montney natural gas production rates at plant capacity for five months
- Advancing high-impact exploration and appraisal programs in the Gulf of America, Vietnam and Côte d'Ivoire—evidence of the strength of our strategic model as well as a demonstration that we continue to invest in our future



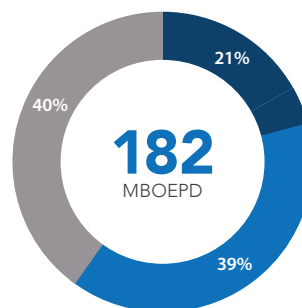
Eric M. Hambly
President and Chief Executive Officer

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"Legacy in Motion reflects who we are as a company, grounded in a strong foundation and always moving forward with purpose."

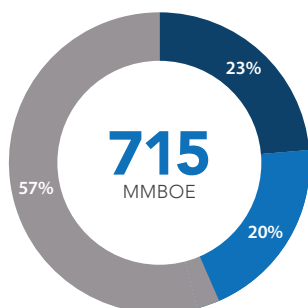
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2025 Production
by Area



- US Onshore: 38 MBOEPD
- Offshore: 71 MBOEPD
- Canada Onshore: 73 MBOEPD

2025 Proved Reserves by Area



■ US Onshore: 168 MMBOE
■ Offshore: 143 MMBOE
■ Canada Onshore: 404 MMBOE

"Our focus remains on a mix of near-term and core operations, creative and nimble exploration efforts, a conservative financial foundation and a focus on our people, the safety of everyone and everything we touch, and a commitment to being a duration-focused company."

Without turning this letter into a dated repetition of disclosures we have previously provided, here are a few operating and strategic highlights from 2025 that provide color and context and show the breadth of our operations and the substantial investments we make in our future:

In the Gulf of America, we:

- maintained industry leading uptime at our key operated facilities,
- purchased the Pioneer Floating Production, Storage and Offloading vessel to enhance the financial performance of our Chinook field,
- spud our Cello and Banjo discoveries, announced in January 2026, and
- participated in the federal government's lease sale, in which we were high bidder for 14 blocks that provide exploration portfolio depth.

In Vietnam, we:

- achieved exploration success at our Lac Da Hong (Pink Camel) and Hai Su Vang (Golden Sea Lion) fields,
- drilled a successful appraisal well at Hai Su Vang (Golden Sea Lion), and
- progressed development of our Lac Da Vang (Golden Camel) field development project, remaining on track for first oil in the fourth quarter of 2026. We expect you'll be reading a lot more about our growing Vietnam business in next year's letter.

In January 2026, we signed a Petroleum Agreement in Morocco's Gharb Deep Offshore block, an agreement giving us a 75 percent working interest with the remainder owned by a governmental entity. Partnering with host governments has been a notable and sometimes under-valued strength of ours: after all, it isn't enough to identify "good rocks" if you can't convert their potential into sustainable financial returns that benefit all parties.

These operational successes are reflected in our 2025 financial performance, a few key metrics of which include:

- Generating \$1.2 billion from continuing operations and \$301.3 million of free cash flow¹
- Distributing \$186 million in dividends
- Repurchasing \$100 million (or 3.6 million shares) in stock
- Ending the year with \$1 billion in net debt
- Achieving operating costs of \$10.89 per BOE

It is both common and tempting in letters like these to focus on financial and operational numbers, most of which reflect past actions and decisions, some of them long in the making. So, I want to supplement this information by sharing that we continue to invest in our people, our technology, our stakeholder relationships and our governance, even though these efforts are often not yet externally visible and their effects not yet measurable. It is these things that, backed by our long-term focus, so strongly align us with the most powerful of all economic drivers I opened this letter describing—the combination of legacy and motion.

Because of the variable and fickle short-term factors I referenced at this letter's opening, any effort to look forward should be undertaken with humility. In this geopolitically, technologically, and financially volatile environment, our focus remains on a mix of near-term and core operations, creative and nimble exploration efforts, a conservative financial foundation and a focus on our people, the safety of everyone and everything we touch, and a commitment to being a duration-focused company.

More specifically, looking at 2026, we are anticipating:

- Prioritizing balance sheet strength and discipline in our capital plans
- Allocating ~75 percent of our capital spending on development and the remainder on exploration and appraisal related activities
- Receiving strong support from our Gulf of America assets while developing our Vietnam assets
- Managing what we cannot anticipate

Thank you for your interest in Murphy. We welcome input and support from all our stakeholders as our legacy moves forward.

Sincerely,

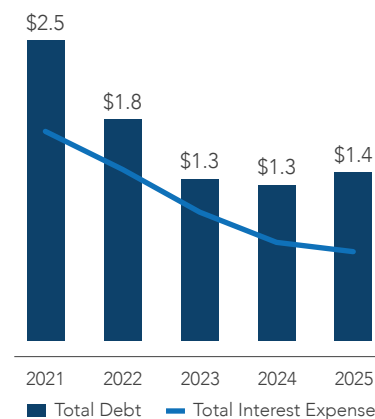


Eric M. Hambly

President and Chief Executive Officer

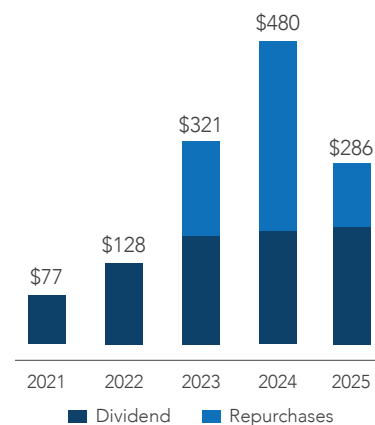
Total Debt and Interest Expense

\$ Billion



Total Return of Capital

\$ Million



Note: Production, reserves and financial metrics may not add due to rounding. Unless otherwise noted, the production, reserves and financial metrics discussed in this Shareholder Letter and accompanying information exclude the noncontrolling interest in MP Gulf of Mexico, LLC (MP GOM), thereby representing only the amounts attributable to Murphy. Proved reserves are based on year-end 2025 third-party audited volumes using SEC pricing.

¹ Free cash flow is calculated as net cash provided by continuing operations activities (including noncontrolling interest) and before noncash working capital changes, less property additions and dry hole costs.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended **December 31, 2025**

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____
Commission file number **1-8590**



MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization) 9805 Katy Fwy, Suite G-200 Houston, Texas (Address of principal executive offices)	71-0361522 (I.R.S. Employer Identification Number) 77024 (Zip Code) (281) 675-9000 (Registrant's telephone number, including area code)
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Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, \$1.00 Par Value	MUR	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 or a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

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

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (as of June 30, 2025) - \$2,375,149,725.

Number of shares of Common Stock, \$1.00 Par Value, outstanding at January 31, 2026 was 142,830,352.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 13, 2026 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

2025 FORM 10-K

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a global oil and natural gas exploration and production (E&P) company, with both onshore and offshore operations and properties. As used in this report, the terms Murphy, Murphy Oil, we, our, its and Company may refer to Murphy Oil Corporation or any one or more of its consolidated subsidiaries.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation. In 2013, the United States (U.S.) refining and marketing business was separated from Murphy Oil Corporation's oil and natural gas E&P business. For reporting purposes, Murphy's E&P activities are subdivided into three geographic segments, including the U.S., Canada and all other countries. Additionally, the Corporate segment includes interest income, interest expense, foreign exchange effects, corporate risk management activities and administrative costs not allocated to the E&P segments. The Company's corporate headquarters are located in Houston, Texas.

In addition to the following information about each business activity, data about Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages [32](#) through [43](#), [77](#) through [81](#), [103](#) through [108](#), and [111](#) through [126](#) of this Form 10-K report.

As part of the Company's underlying operations, the Company is continually monitoring its greenhouse gas (GHG) emissions and impact on the environment as well as other social and environmental aspects of its business. See "[Sustainability](#)" on page [9](#).

Interested parties may obtain the Company's public disclosures filed with the Securities and Exchange Commission (SEC), including Form 10-K, Form 10-Q, Form 8-K and other documents, by accessing the Investor Relations section of Murphy Oil Corporation's Website at www.murphyoilcorp.com.

Exploration and Production

The Company produces crude oil and condensate (collectively, crude oil), natural gas and natural gas liquids (NGLs) primarily in the U.S. and Canada and explores for crude oil, natural gas and NGLs (collectively, oil and natural gas) in targeted areas worldwide.

During 2025, Murphy's principal E&P activities were conducted in the U.S. by wholly-owned Murphy Exploration & Production Company - USA and its subsidiaries, in Canada by wholly-owned Murphy Oil Company Ltd. and its subsidiaries, and in Brazil, Brunei, Côte d'Ivoire and Vietnam by wholly-owned Murphy Exploration & Production Company - International and its subsidiaries. Murphy's operations and production in 2025 were in the U.S., Canada and Brunei.

In January 2026, Murphy signed a Petroleum Agreement securing an operated position in Morocco's Gharb Deep Offshore deepwater block which covers more than 4 million acres. Murphy holds a 75% working interest in the block, with the remaining 25% working interest held by the Office National des Hydrocarbures et des Mines. The Petroleum Agreement does not include any firm well commitments in the initial three-year exploration phase.

Unless otherwise indicated, all references to the Company's U.S. Offshore and total oil and natural gas production, sales volumes, and proved reserves include the noncontrolling interest in MP Gulf of Mexico, LLC (MP GOM; see further details below).

Murphy's worldwide 2025 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 188,682 barrels of oil equivalent per day (BOEPD), an increase of 2.4% compared to 2024.

For further details on business execution, see "[Management's Discussion and Analysis of Financial Condition and Results of Operations](#)" starting on page [32](#). For further details on 2025 production and sales volume see pages [36](#) to [37](#).

PART I

Item 1. Business - Continued

United States

In the U.S., Murphy produces oil and natural gas primarily from fields in the Gulf of America and in the Eagle Ford Shale area of South Texas. The Company produced 93,289 barrels (BBL) of crude oil and NGLs (collectively, liquids) per day and approximately 85 million cubic feet (MMCF) of natural gas per day in the U.S. in 2025. These amounts represented 90% of the Company's total worldwide liquids and 17% of worldwide natural gas production volumes.

Offshore

The Company holds rights to approximately 556 thousand gross acres in the Gulf of America. During 2025, approximately 65% of total U.S. hydrocarbon production was produced at fields in the Gulf of America, of which approximately 91% was derived from ten fields, including the operated Mormont, Khaleesi, Cascade and Chinook, Marmalard, Dalmatian, Neidermeyer and Powerball fields, as well as the non-operated St. Malo, Kodiak and Lucius fields. Total average daily production in the Gulf of America in 2025 was 61,233 BBL of liquids and 52 MMCF of natural gas. At December 31, 2025, Murphy had total proved reserves for Gulf of America fields of 112.1 million BBL of liquids and 69.2 billion cubic feet (BCF) of natural gas.

Onshore

The Company holds rights to approximately 130 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and natural gas play. During 2025, approximately 35% of total U.S. hydrocarbon production was produced in the Eagle Ford Shale. Total 2025 production in the Eagle Ford Shale area was 32,056 BBL of liquids per day and 33 MMCF per day of natural gas. At December 31, 2025, the Company's proved reserves for the U.S. Onshore business totaled 137.9 million BBL of liquids and 182.0 BCF of natural gas.

Canada

In Canada, the Company holds working interests in the Tupper Montney (100% working interest), the Kaybob Duvernay and two non-operated offshore assets – the Hibernia and Terra Nova fields, located offshore Newfoundland and Labrador in the Jeanne d'Arc Basin. In 2023, the Company sold a portion of its working interest in the Kaybob Duvernay and the entire 30% non-operated working interest in the Placid Montney.

Onshore

Murphy has approximately 139 thousand gross acres of the Tupper Montney mineral rights located in northeast British Columbia. In addition, the Company holds a 70% working interest in the Kaybob Duvernay lands in Alberta. The Company has approximately 167 thousand gross acres of the Kaybob Duvernay mineral rights. Daily production in 2025 for Canada Onshore averaged 3,479 BBL of liquids and 423 MMCF of natural gas. Total Canada Onshore proved liquids and natural gas reserves at December 31, 2025, were approximately 23.7 million BBL and 2.3 trillion cubic feet, respectively.

Offshore

The Company holds a non-operated interest in approximately 130 thousand gross acres offshore Canada. Murphy has a 6.5% working interest in Hibernia Main, a 4.3% working interest in Hibernia South Extension and an 18.0% working interest in Terra Nova. Oil production in 2025 was 6,981 BBL of oil per day for the two offshore Canadian fields. Terra Nova resumed production during the fourth quarter of 2023, following the completion of an asset life extension project. Total proved reserves for Canada Offshore at December 31, 2025 were approximately 19.4 million BBL of liquids and 8.6 BCF of natural gas.

Brazil

The Company holds a 20% non-operated working interest in one block in the offshore regions of the Sergipe-Alagoas Basin (SEAL) in Brazil (SEAL-M-637) and holds a 100% working interest in three blocks in the Potiguar Basin (POT-M-857, POT-M-863 and POT-M-865).

Murphy's total acreage position in Brazil as of December 31, 2025 was approximately 960 thousand gross acres, offsetting several major discoveries. There are no well commitments.

PART I

Item 1. Business - Continued

Brunei

The Company has a working interest of 8.051% in Block CA-1 as of December 31, 2025. Oil production in 2025 was 275 BBL of oil per day.

Total proved reserves for our Jagus East discovery in Block CA-1 at December 31, 2025 were approximately 0.2 million BBL of liquids and 157 MMCF of natural gas. Block CA-1 covers 2 thousand gross acres.

Côte d'Ivoire

Murphy operates five offshore PSCs in the Tano Basin offshore Côte d'Ivoire, Africa, with the five blocks having a total area of 1.4 million gross acres. Murphy holds a 90% working interest in four blocks and an 85% working interest in the fifth block. Société Nationale d'Opérations Pétrolières de la Côte d'Ivoire holds the remaining working interest for each block.

The three-well exploration drilling campaign includes Civette-1X drilled on Block CI-502, Caracal-1X currently drilling on Block CI-102, and Bubale-1X to be drilled on Block CI-709 in 2026. These three wells will satisfy drilling Minimum Work Program commitments on each of these blocks. There will be no further well commitments on these three blocks until June 2028. Subsequent to year-end, the Civette-1X exploration well reached a total depth of 13,950 feet and encountered non-commercial hydrocarbons across multiple intervals. Also subsequent to year end, the Caracal-1X exploration well reached a total depth of 8,534 feet and will be plugged and abandoned as a dry hole after encountering non-commercial hydrocarbon shows.

The remaining blocks, CI-103 and CI-531, have elections in December 2026, with the option to enter a Second Exploration Period carrying well commitments.

Vietnam

The Company holds an interest in 7.3 million gross acres, consisting of 65% working interest in Blocks 144 & 145, and a 40% working interest in Block 15-1/05 and Block 15-2/17. The Company is the operator of each of the three Production Sharing Contracts (PSCs).

Block 15-1/05 contains the Lac Da Vang (Golden Camel) discovered field in the Cuu Long Basin where, in 2023, the Company received government approval of the field development plan, and the Board of Directors of the Company (the Board) sanctioned the project. Development activity is in progress, with first oil planned in 2026. The Lac Da Trang-1X (White Camel) exploration well was drilled in April 2019 and encountered 320 feet of pay with light oil in one reservoir. The Company drilled the Lac Da Hong-1X (Pink Camel) exploration well in 2025 and encountered 106 feet of net oil pay from one reservoir and continues to progress post-drill evaluations. A lease extension was granted with accompanying commitments which are being actively progressed.

In Block 15-2/17, in the fourth quarter 2024, the Company drilled an oil discovery at the Hai Su Vang-1X (Golden Sea Lion) exploration well, which encountered 370 feet of net pay from two reservoirs. The Hai Su Vang-2X appraisal well to this discovery was drilled in the fourth quarter of 2025 and encountered 429 feet of net pay from two reservoirs. Additional evaluation is ongoing and future appraisal drilling will be conducted. A lease extension was granted with accompanying commitments which are being actively progressed.

In Blocks 144 & 145, the Company acquired 2D seismic in 2013 and undertook seabed surveys in 2015 and 2016. The Company intends to request a further extension to complete the remaining work commitment.

Total proved reserves for Lac Da Vang (Golden Camel) field development in Vietnam at December 31, 2025 were approximately 12.1 million BBL of liquids and 7.4 BCF of natural gas.

PART I

Item 1. Business - Continued

Proved Reserves

Total proved reserves for crude oil, natural gas and NGLs as of December 31, 2025 are presented in the following table.

	Proved Reserves			
	All Products	Crude Oil	Natural Gas Liquids	Natural Gas ¹
	(MMBOE)	(MMBBL)		(BCF)
Proved Developed Reserves:				
United States	197.8	150.8	19.2	166.4
Onshore	96.7	64.1	14.5	108.5
Offshore ²	101.1	86.7	4.7	57.9
Canada	220.9	22.1	2.5	1,178.5
Onshore	204.7	7.3	2.5	1,169.9
Offshore	16.2	14.8	–	8.6
Other	0.2	0.2	–	0.2
Total proved developed reserves	418.9	173.1	21.7	1,345.1
Proved Undeveloped Reserves:				
United States	94.1	67.4	12.6	84.8
Onshore	71.6	48.0	11.3	73.5
Offshore ³	22.5	19.4	1.3	11.3
Canada	203.7	16.1	2.4	1,110.4
Onshore	199.1	11.5	2.4	1,110.4
Offshore	4.6	4.6	–	–
Other	13.3	12.1	–	7.4
Total proved undeveloped reserves	311.1	95.6	15.0	1,202.6
Total proved reserves ⁴	730.0	268.7	36.7	2,547.7

¹ Includes proved natural gas reserves to be consumed in operations as fuel of 54.2 BCF, 35.1 BCF and 7.4 BCF for the U.S., Canada and Other, respectively, with 1.7 BCF of this attributable to the noncontrolling interest in MP GOM.

² Includes proved developed reserves of 13.1 million barrels of oil equivalent (MMBOE), consisting of 12.1 million barrels (MMBBL) of oil, 0.4 MMBBL of NGLs and 3.9 BCF of natural gas, attributable to the noncontrolling interest in MP GOM.

³ Includes proved undeveloped reserves of 1.9 MMBOE, consisting of 1.8 MMBBL of oil and 0.3 BCF of natural gas, attributable to the noncontrolling interest in MP GOM.

⁴ Includes proved reserves of 15.0 MMBOE, consisting of 13.9 MMBBL of oil, 0.4 MMBBL of NGLs and 4.2 BCF of natural gas, attributable to the noncontrolling interest in MP GOM.

PART I

Item 1. Business - Continued

Murphy Oil's 2025 total proved reserves and proved undeveloped reserves are reconciled from 2024 as presented in the table below:

<i>(Millions of barrels of oil equivalent)</i> ¹	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	729.0	292.8
Revisions of previous estimates	26.0	22.8
Extensions and discoveries	43.0	42.4
Conversions to proved developed reserves	–	(45.6)
Purchases of properties	4.3	1.5
Sale of properties	(3.4)	(2.8)
Production	(68.9)	–
End of year ²	730.0	311.1

¹ For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six thousand cubic feet of natural gas to one barrel of oil.

² Includes 15.0 MMBOE and 1.9 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.

Production of 68.9 MMBOE, 3.4 MMBOE of divestment in the Eagle Ford Shale, and price related losses of 3.0 MMBOE were fully offset by extensions of 4.9 MMBOE in the Eagle Ford Shale and 38.1 MMBOE in Canada, 4.3 MMBOE of acquisition in the Eagle Ford Shale, as well as performance related increases of 8.2 MMBOE in Canada, 9.1 MMBOE in the Eagle Ford Shale, 10.7 MMBOE in the Gulf of America, and 1.0 MMBOE in Other regions.

Murphy's total proved undeveloped reserves at December 31, 2025 increased 18.3 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2025 were predominantly attributable to the Eagle Ford Shale in South Texas and the Tupper Montney and the Kaybob Duvernay in onshore Canada. These U.S. and Canadian assets had active development work ongoing during the year, and new drilling locations were added in the Gulf of America. The majority of proved undeveloped reserves associated with revisions of previous estimates was the result of performance adjustments in the Tupper Montney and the Eagle Ford Shale, partially offset by increased royalty rates and accelerated royalty incentive payouts arising from higher commodity prices in the Tupper Montney. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in the Tupper Montney, the Gulf of America, and the Eagle Ford Shale.

The Company spent approximately \$690 million in 2025 to convert proved undeveloped reserves to proved developed reserves. In the next three years, the Company expects to spend a range of approximately \$450 million to \$800 million per year to move current undeveloped proved reserves to the developed category. The anticipated level of spending in 2026 primarily includes drilling and development in the Gulf of America, the Eagle Ford Shale, the Tupper Montney, the Kaybob Duvernay and Vietnam areas.

At December 31, 2025, proved reserves are included for several development projects, including oil developments in the Eagle Ford Shale in South Texas, the Gulf of America, the Kaybob Duvernay in onshore Canada and Lac Da Vang (Golden Camel) in Vietnam; as well as natural gas developments in the Tupper Montney in onshore Canada. Total proved undeveloped reserves associated with various development projects at December 31, 2025 were approximately 311.1 MMBOE, which represents 43% of the Company's total proved reserves.

Certain development projects have proved undeveloped reserves that will take more than five years to bring to production. Projects in deepwater fields in the Gulf of America and Canada Offshore include four undeveloped locations that exceed this five-year window. Total reserves associated with the four locations amount to less than 1% of the Company's total proved reserves at year end 2025. The development of certain reserves extends beyond five years due to limited well slot availability, thus making it necessary to wait for depletion of other wells prior to initiating further development of these locations or behind-pipe completions with significant capital costs that categorize them as undeveloped.

PART I

Item 1. Business - Continued

Murphy Oil's Reserves Processes and Policies

All estimates of reserves are made in compliance with SEC Rule 4-10 of Regulation S-X, which states that "proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations." Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

Murphy has established both internal and external controls for estimating proved reserves that follow the guidelines set forth by the SEC for oil and gas reporting. Crude oil, natural gas and NGLs reserve estimates are developed or reviewed by Qualified Reserves Estimators (QREs). QREs are technical professionals embedded within the asset teams. QRE qualification generally requires a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of reserves, and either a bachelors or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science from a college or university of recognized stature, or the equivalent thereof from an appropriate government authority or professional organization. Larger business units of the Company also employ Regional Reserves Coordinators who coordinate and provide oversight of the reserve submissions to senior management and the Corporate Reserves group. Murphy provides annual training to all Company reserves estimators to ensure SEC requirements associated with reserves estimation and Form 10-K reporting are fulfilled.

Proved reserves are consolidated and reported through the Corporate Reserves group. Murphy's General Manager Corporate Reserves (Reserves General Manager) leads the Corporate Reserves group that also includes Corporate Reserve engineers and support staff, all of which are independent of the Company's oil and natural gas operational management and technical personnel. The Reserves General Manager joined Murphy in 2020 and has more than 34 years of industry experience. He has a Bachelor of Science in Mechanical Engineering and is also a licensed Professional Engineer in the State of Texas. The Reserves General Manager reports to the Executive Vice President and Chief Financial Officer and makes annual presentations to the Board about the Company's reserves. The Reserves General Manager and the Corporate Reserve engineers review and discuss reserves estimates directly with the Company's technical staff in order to make every effort to comply with the rules and regulations of the SEC.

The Reserves General Manager coordinates and oversees the third-party audits which are performed annually. In 2025, third party audits were conducted for proved reserves covering 95.8% of total proved reserves. All audits conducted during this period were within the established +/- 10.0% tolerance.

Ryder Scott Company ("Ryder Scott") performed audits for certain reserve estimates of Murphy's U.S. fields as of December 31, 2025. The Ryder Scott summary reports are filed as exhibits to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 23 years of industry experience, joining Ryder Scott over 20 years ago. He is a registered Professional Engineer in the State of Texas.

McDaniel & Associates ("McDaniel") performed audits for certain reserve estimates of our onshore Canadian fields as of December 31, 2025. The McDaniel summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for McDaniel has over 18 years of experience in the estimation and evaluation of reserves with McDaniel. He is a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta.

Netherland, Sewell & Associates, Inc. ("NSAI") performed audits for certain reserve estimates of our Gulf of America fields as of December 31, 2025. The NSAI summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for NSAI has over 22 years of industry experience, joining NSAI over 16 years ago.

GLJ Ltd. ("GLJ") performed audits for certain reserve estimates of our offshore Canadian fields as of December 31, 2025. The GLJ summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for GLJ has over 22 years of experience in the estimation and evaluation of reserves with GLJ. He is a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta.

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Item 1. Business - Continued

To ensure accuracy and security of reported reserves, the proved reserves estimates are coordinated in industry-standard software with access controls for approved users. In addition, Murphy complies with internal controls concerning the various business processes related to reserves.

More information regarding Murphy's estimated quantities of proved reserves of crude oil, natural gas and NGLs for the last three years are presented by geographic area on pages [113](#) through [120](#) of this Form 10-K report. Murphy currently has no oil and natural gas reserves from non-traditional sources. Murphy has not filed and is not required to file any estimates of its total proved oil or natural gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the SEC. Annually, Murphy reports gross reserves of properties operated in the U.S. to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil and NGLs production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2025 are starts on page [35](#) of this Form 10-K report.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page [38](#) of this Form 10-K report.

Supplemental disclosures relating to oil and natural gas producing activities are reported on pages [111](#) through [126](#) of this Form 10-K report.

Acreage and Well Count

At December 31, 2025, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. "Gross" acres are those in which all or part of the working interest is owned by Murphy. "Net" acres are the portions of the gross acres attributable to Murphy's interest.

Area (Thousands of acres)	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
United States Onshore	109	97	21	20	130	117
Offshore	55	25	501	268	556	293
Total United States	164	122	522	288	686	410
Canada Onshore	141	114	165	130	306	244
Offshore	102	11	28	1	130	12
Total Canada	243	125	193	131	436	256
Brunei	2	–	–	–	2	–
Brazil	–	–	960	811	960	811
Côte d'Ivoire	–	–	1,421	1,270	1,421	1,270
Vietnam	–	–	7,324	4,571	7,324	4,571
Totals	409	247	10,420	7,071	10,829	7,318

Certain undeveloped acreage held by the Company will expire in the next three years.

Scheduled expirations in 2026 include 4,267 thousand net acres in Vietnam, 558 thousand net acres in Côte d'Ivoire and 28 thousand net acres in U.S. Offshore. The Company plans to seek extensions for the expiring acres in Vietnam.

Acreage currently scheduled to expire in 2027 includes 12 thousand net acres in U.S. Offshore.

Scheduled expirations in 2028 include 774 thousand net acres in Brazil, 712 thousand net acres in Côte d'Ivoire, 255 thousand net acres in Vietnam, 7 thousand net acres in U.S. Offshore and 2 thousand net acres in Canada Onshore.

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Item 1. Business - Continued

As used in the three tables that follow, “gross” wells are the total wells in which all or part of the working interest is owned by Murphy, and “net” wells are the total of the Company’s fractional working interests in gross wells expressed as the equivalent number of wholly-owned wells. An “exploratory” well is drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area. A “development” well is drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

The following table shows the number of oil and natural gas wells producing or capable of producing at December 31, 2025.

		Oil Wells		Natural Gas Wells	
		Gross	Net	Gross	Net
United States	Onshore	1,251	1,008	30	5
	Offshore	83	37	12	5
Total United States		1,334	1,045	42	10
Canada	Onshore	18	13	369	352
	Offshore	50	5	–	–
Total Canada		68	18	369	352
Totals		1,402	1,063	411	362

Murphy’s net wells drilled and completed in the last three years are shown in the following table.

	United States		Canada		Other		Totals	
	Productive	Dry	Productive	Dry	Productive	Dry	Productive	Dry
2025								
Exploration	–	–	–	–	0.8	0.9	0.8	0.9
Development	33.3	–	13.0	–	–	–	46.3	–
2024								
Exploration	0.3	0.8	–	–	–	–	0.3	0.8
Development	23.9	–	15.3	–	–	–	39.2	–
2023								
Exploration	–	1.3	–	–	–	–	–	1.3
Development	34.1	–	15.1	–	–	–	49.2	–

Murphy’s drilling wells in progress at December 31, 2025 are shown in the following table. The year-end well count includes wells awaiting various completion operations.

		Exploration		Development		Total	
		Gross	Net	Gross	Net	Gross	Net
United States	Onshore	–	–	25.0	18.3	25.0	18.3
	Offshore	2.0	1.0	1.0	0.1	3.0	1.1
Canada	Onshore	–	–	4.0	2.8	4.0	2.8
	Offshore	–	–	1.0	0.1	1.0	0.1
Other		1.0	0.4	1.0	0.4	2.0	0.8
Totals		3.0	1.4	32.0	21.7	35.0	23.1

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Item 1. Business - Continued

Sustainability

Environment and Climate Change

We understand that our industry, and the use of our products, create emissions – which raise climate change concerns. At the same time, access to affordable and reliable energy is essential to improving the world’s quality of life and the functioning of the global economy. We believe that as the energy economy transitions, oil and natural gas will continue to play a vital role in the long-term energy mix.

We are committed to reducing our Scope 1 and 2 GHG emissions and are focused on understanding and mitigating our climate change risks. To guide our climate change strategy, Murphy has adopted a climate change position, and we are setting meaningful emissions reduction goals for our operated assets. The Company has established a Scope 1 and 2 GHG emissions intensity reduction target of 15% to 20% by 2030 from our 2019 level, excluding our discontinued and divested Malaysia operations. In addition, we have endorsed the goal of eliminating routine flaring by 2030, under the current World Bank definition of routine flaring.

Murphy recognizes that emissions are only one element of our total environmental footprint. Protecting natural resources is also an important factor in our overall sustainability efforts. See our 2025 Sustainability Report, located on the Company’s website, for details, which is not incorporated by reference hereto.

Further, we are subject to various international, foreign, national, state, provincial and local environmental, health and safety laws and regulations, including related to the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including GHG emissions; wildlife, habitat and water protection; the placement, operation and decommissioning of production equipment; and the health and safety of our employees, contractors and communities where our operations are located.

U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). CERCLA and similar state statutes impose joint and several liabilities, without regard to fault or legality of the conduct, on current and past owners or operators of a site where a release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Although CERCLA generally exempts “petroleum” from regulation, in the course of our operations, we may and could generate wastes that may fall within CERCLA’s definition of hazardous substances and may have disposed of these wastes at disposal sites owned and operated by others.

Water discharges. The U.S. Clean Water Act and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into regulated waters. The U.S. Oil Pollution Act (OPA) imposes certain duties and liabilities on the owner or operator of a facility, vessel or pipeline that is a source of or that poses the substantial threat of an oil discharge, or the lessee or permittee of the area in which a discharging offshore facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill.

U.S. Bureau of Ocean Energy Management (BOEM) and the U.S. Bureau of Safety and Environmental Enforcement (BSEE) requirements. BOEM and BSEE have regulations applicable to lessees in federal waters that impose various safety, permitting and certification requirements applicable to exploration, development and production activities in the Gulf of America and also require lessees to have substantial U.S. assets and net worth or post bonds or other acceptable financial assurance that the regulatory obligations will be met. These include, in the Gulf of America, well design, well control, casing, cementing, real-time monitoring and subsea containment, among other items. Under applicable requirements, BOEM evaluates the financial strength and reliability of lessees and operators active on the U.S. Outer Continental Shelf, including the Gulf of America. If the BOEM determines that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance.

Air emissions and climate change. The U.S. Clean Air Act and comparable state laws and regulations govern emissions of various air pollutants through the issuance of permits and other authorization requirements. Since 2009, the U.S. Environmental Protection Agency (EPA) has been monitoring and regulating GHG emissions,

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Item 1. Business - Continued

including carbon dioxide and methane, from certain sources in the oil and natural gas sector due to their association with climate change. In addition, international climate efforts have resulted in commitments from many countries to reduce GHG emissions and have called for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs.

Murphy is currently required to report GHG emissions from its U.S. operations in the Gulf of America and onshore in South Texas and from its onshore Canadian business in British Columbia and Alberta. In Canada, Murphy is subject to GHG regulations and resultant carbon pricing programs specific to the jurisdiction of operation. Any limitations or further regulation of GHGs, such as a cap and trade system, technology mandate, emissions tax, or expanded reporting requirements, could cause the Company to restrict operations, curtail demand for hydrocarbons generally, and/or cause costs to increase. Examples of cost increases include costs to operate and maintain facilities, install pollution emission controls and administer and manage emissions trading programs.

On March 8, 2024, the EPA published its final rules imposing new and stricter requirements for methane monitoring, reporting, and emissions control at certain oil and natural gas facilities. Further, the EPA amended its GHG Reporting Rule on May 14, 2024 to modify certain calculation methodologies, changes to the general reporting structure, and the EPA's treatment of advanced measurement technologies. Ultimately, both new rules will impact how much reporters owe under the new methane waste emissions charge (WEC) established under the Inflation Reduction Act (IRA) in 2022 and finalized in November 2024.

In January 2025, however, President Trump signed a series of executive orders that call upon the EPA to reassess the endangerment finding for GHGs under the Clean Air Act, direct federal executive departments and agencies to freeze rules that have not taken effect, to identify and exercise emergency authorities to facilitate conventional energy production, transportation, and refining, and mandate a review of existing regulations that may burden domestic energy development.

As part of this shift, the Administration moved to halt the implementation of the WEC citing concerns about statutory authority, economic impacts on domestic energy production, and the need for further evaluation of methane measurement methodologies. This action resulted in the EPA withdrawal of WEC's supporting guidance, paused enforcement preparations, and announced its intent to reconsider the rule. In May 2025, the agency issued a final rule formally removing the WEC from the Code of Federal Regulations. The One Big Beautiful Bill Act (OBBBA) passed in July 2025 postponed the implementation of the WEC to 2034.

In September 2025, the EPA proposed a rollback of the Greenhouse Gas Reporting Program (GHGRP). The proposal would eliminate reporting requirements for most source categories after reporting year 2024 and postpone Subpart W reporting for petroleum and natural gas systems until 2034. If finalized, this would significantly reduce federal GHG data collection and delay methane reporting for nearly a decade. Together, the repeal of the WEC regulations, the postponement of the WEC to 2034 and the proposed rollback of the GHGRP create substantial uncertainty for the future of overall federal methane regulation. The future of both will depend on the EPA's rulemaking process, potential litigation, and possible congressional involvement.

Endangered and threatened species. The U.S. Endangered Species Act was established to protect endangered and threatened species. If a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds, under the Migratory Bird Treaty Act, and marine mammals under the Marine Mammal Protection Act.

As noted above, Murphy is subject to various laws and regulatory regimes governing similar matters in other jurisdictions in which it operates. More specifically, Murphy's operations in Canada are subject to and conducted under Canadian laws and regulations that address many of the same environmental, health and safety issues as those in the U.S., including, without limitation, pollution and contamination, air quality and emissions, water discharges and other health and safety concerns.

Further, on February 12, 2026, the EPA announced the repeal of its 2009 "Endangerment Finding" under the Clean Air Act, which found that GHGs endanger the public health and welfare of current and future generations and emissions of GHGs from motor vehicles contribute to GHG pollution. The repeal calls into question EPA's authority to regulate GHGs, as well as EPA's prior scientific assessment of climate change risks. Litigation regarding the repeal is anticipated and it is unclear how the repeal will impact EPA's regulation of GHG emissions going forward.

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Item 1. Business - Continued

Health and Safety

Murphy's commitment to safety is strong, and so are our actions to protect our workforce and communities. Our employees are our most valuable asset. Murphy strives to achieve incident-free operations through continuous improvement processes managed by the Company's Health, Safety, Environment (HSE) Management System, which engages all personnel, contractors and partners associated with Murphy operations and facilities and provides a consistent method for integrating HSE concepts into our procedures and programs. We work hard to build a culture of safety across our organization, with regular training, exercise drills and key targeted safety initiatives.

Safety. The Company is subject to the requirements of the U.S. Occupational Safety and Health Act (OSHA) and comparable foreign and state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information regarding hazardous materials used or produced in Murphy's operations be maintained and provided to employees, state and local government authorities and citizens. In Canada, the Company is subject to Federal Occupational Health and Safety Legislation, the provincially-administered Occupational Health and Safety Act (Alberta), the Workers Compensation Act (British Columbia) and the Workplace Hazardous Materials Information System.

Environmental, Social and Governance (ESG) Disclosure

Our annual sustainability report is informed by internationally recognized ESG reporting frameworks and standards, including Sustainability Accounting Standards Board, Task Force on Climate-related Financial Disclosures (TCFD), Global Reporting Initiative, Ipieca and American Petroleum Institute.

As this is an area of continual improvement across our industry, we strive to update our disclosures in line with operating developments and with emerging best practice ESG reporting standards. In 2025, we published our seventh annual sustainability report, located on the Company's website, which is not incorporated by reference hereto.

Human Capital Management

At Murphy, we believe in providing energy that empowers people, and that is what our 813 employees do every day. As of December 31, 2025, we had 542 office-based employees and 271 field employees, all of whom are guided by our mission, vision, values and behaviors. Together with the Executive Leadership Team, the Senior Vice President, Human Resources, Administration and Communications, who reports directly to our President and Chief Executive Officer, is responsible for developing and executing our human capital management strategy. This includes the attraction, recruitment, development and engagement of talent to deliver on our strategy, the design of employee compensation, health and welfare benefits, and talent programs. We focus on the following factors in order to implement and develop our human capital strategy:

- Employee Compensation Programs
- Employee Performance and Feedback
- Talent Development and Training
- Health and Welfare Benefits
- Employee Engagement

The Board receives related updates from the Senior Vice President, Human Resources, Administration and Communications on a regular basis including the review of compensation, benefits, succession and talent development.

Employee Compensation Programs

Our purpose, to provide energy that empowers people, includes tying a portion of our employees' pay to performance in a variety of ways, including incentive compensation and performance-based bonus programs, while maintaining the best interest of stockholders. We benchmark for market practices and regularly review our compensation and hiring acceptance rates against the market to ensure competitiveness to attract and retain the best talent. We believe our current practices align our employees' compensation with the interests of our stockholders and support our focus on cash flow generation, capital return and environmental stewardship. To

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Item 1. Business - Continued

enhance employee understanding of their total remuneration package extended by Murphy, we introduced Total Reward Statements for employees in the U.S., Canada and Vietnam. For further details on the Company's compensation framework, please see the Compensation Discussion and Analysis section of the forthcoming Proxy Statement relating to the Annual Meeting of Stockholders on May 13, 2026.

Employee Performance and Feedback

We are committed to efforts to enhance our employees' professional growth and development through feedback that utilizes our internal performance management system (Murphy Performance Management - MPM). The purpose of the MPM process is to show our commitment to the development of all employees and to better align rewards with Company and individual performance. The goals of the MPM process are the following:

- Drive performance that aligns with the Company's mission, vision, values and behaviors;
- Develop employee capabilities through effective feedback and coaching; and
- Maintain a process that is consistent throughout the organization to measure employee performance that is tied to the Company's and stockholders' interests.

All employees' performance is evaluated at least annually through self-assessments that are reviewed in discussions with supervisors. Employees' performance is evaluated on various key performance indicators set annually, including contributions toward executing our Company's goals and business strategy and behaviors that support our mission, vision, values.

Talent Development and Training

Employees are able to participate in continuous training and development, with the goal of equipping them for success and providing increased opportunities for growth. Through our digital platform, My Murphy Learning, employees have access to LinkedIn Learning with more than 10,000 courses, Continuing Education Unit credit and certification opportunities, and access to expert instructors. We also administer mandatory compliance training for our employees through My Murphy Learning with 100% utilization. Finally, we provide a tuition reimbursement program for those who choose to acquire additional knowledge to increase their effectiveness in their present position or to prepare for career advancement.

To enhance employees' commitment to and understanding of the Company's Scorecard, we introduced a training course entitled, *Understanding Your Annual Incentive Plan*, which covers all metrics in our scorecard. This training opportunity, in particular, enhanced the business acumen of our employee base, as well as brought renewed focus to how we measure success.

We strive to empower our leadership with programs that offer career advancement for experienced and emerging leaders. In 2025, approximately 135 leaders participated in programs, from top-rated institutions, addressing focus areas such as strategic agility, decision making, building high-performing teams and enhancing trust. Furthermore, we implemented a Business Functions Career Map to enhance the development of about 100 business professionals in our Controllers, Global Planning and Performance, Tax, Treasury and related functions.

We encourage employee engagement and solicit feedback through internal surveys, focus groups and town hall meetings to gain insight into workplace experiences. Employees are provided opportunities to raise suggestions and collaborate with leadership to improve programs and increase their alignment with Murphy's mission, vision, values and behaviors.

To monitor the effectiveness of our human capital investment and development programs, we track voluntary turnover. This data is shared on a regular basis with our Executive Leadership Team, who use it, in addition to other pertinent data, to develop our human capital strategy. In 2025, our voluntary employee turnover rate, including retirements, was 4%.

Health and Welfare Benefits

We believe that doing our part to aid in maintaining the health and welfare of our employees is a critical element of Murphy's success. As such, we provide our employees and their families with a comprehensive set of subsidized benefits that are competitive and aligned with Murphy's mission, vision, values and behaviors. We also believe that the well-being of our employees is enhanced when they can give back to their local

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Item 1. Business - Continued

communities or charities through programs like the Company Matching Gift Program, the "Impact - Murphy Makes a Difference" Program, or on their own with a Company match for donations.

Finally, we offer an Employee Assistance Program that provides confidential assistance to employees and their immediate family members for mental and physical well-being, as well as legal and financial issues. We also maintain an Ethics Hotline that is available to all our employees to report, anonymously if desired, any matter of concern. Communications to the hotline, which is facilitated by an independent third party, are routed to appropriate functions, Human Resources, Law or Compliance, for investigation and resolution.

Employee Engagement

At Murphy, we strive for excellence in our people and our work. We believe that having employees who reflect a broad range of backgrounds, experiences and perspectives contributes to a more productive, engaged workforce and a more enriching environment for everyone. This belief underlies Murphy's commitment to fostering an inclusive workplace where the most talented want to work and where our employees understand our culture of belonging. In furtherance of that commitment, Murphy, through its policies and its actions, requires strict compliance with all anti-harassment and anti-discrimination laws and does not tolerate harassment or discrimination of any kind based on any protected characteristic.

Finally, we support interest-based groups such as sports and charity volunteering in our communities.

Website Access to SEC Reports

Murphy Oil's internet address is <http://www.murphyoilcorp.com>. The information contained on the Company's Website is not part of, or incorporated into, this report on Form 10-K.

The Company's 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 Murphy's Website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. You may also access these reports at the SEC's Website at <http://www.sec.gov>.

Item 1A. RISK FACTORS

The Company faces risks in the normal course of business and through global, regional and local events that could have an adverse impact on its reputation, operations, and financial performance. The Board exercises oversight of the Company's enterprise risk management program, which includes strategic, operational, cybersecurity and financial matters, as well as compliance and legal risks. The Board receives updates annually on the risk management processes.

The following are some important factors that could cause the Company's actual results to differ materially from those projected in any forward-looking statements. If any of the events or circumstances described in any of the following risk factors occurs, our business, results of operations and/or financial condition could be materially and adversely affected, and our actual results may differ materially from those contemplated in any forward-looking statements we make in any public disclosures.

Price Risk Factors

Volatility in the global prices of oil and natural gas can significantly affect the Company's operating results, cash flows and financial condition.

Among the most significant variable factors impacting the Company's results of operations are the sales prices for the hydrocarbons that it produces. Many of the factors influencing prices of oil and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of, and demand for oil and natural gas;
- the ability of the members of the Organization of the Petroleum Exporting Countries (OPEC) and certain non-OPEC members, for example, Russia, to agree to maintain or adjust production levels;

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Item 1A. Risk Factors - Continued

- the production levels of non-OPEC countries, including, among others, production levels in the North American shale plays;
- political instability or armed conflict in oil and natural gas producing regions, such as the Russia-Ukraine and Israeli-Palestinian conflicts and political instability in Venezuela and Iran;
- the level of drilling, completion and production activities by other E&P companies, and variability therein, in response to market conditions;
- changes in weather patterns and climate, including those that may result from climate change;
- natural disasters such as hurricanes and tornadoes, including those that may result from climate change;
- the price, availability and the demand for and of alternative and competing forms of energy, such as nuclear, hydroelectric, wind or solar;
- the effect of conservation efforts and focus on climate-change;
- technological advances, such as artificial intelligence (AI) and data center development, affecting energy consumption and energy supply;
- increased activism against, or change in public sentiment for, oil and natural gas exploration, development, and production activities and considerations including climate change and the transition to a lower carbon economy;
- the occurrence or threat of epidemics or pandemics, such as the outbreak of COVID-19, or any government response to such occurrence or threat which may lower the demand for hydrocarbon fuels;
- domestic and foreign governmental regulations, taxes and other actions, including tariffs, economic sanctions and further legislation requiring, subsidizing or providing tax benefits for the use or generation of alternative energy sources and fuels; and
- general economic conditions worldwide, including inflationary conditions and related governmental policies and interventions.

West Texas Intermediate (WTI) crude oil prices averaged \$64.81 per barrel in 2025, compared to \$75.72 in 2024 and \$77.62 in 2023. Certain U.S. and Canadian crude oils are priced from oil indices other than WTI, and these indices are influenced by different supply and demand forces than those that affect WTI prices. The most common crude oil indices used to price the Company's crude include Mars, WTI Houston Magellan East Houston, Heavy Louisiana Sweet and Brent.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was \$3.54 per million British Thermal Units (MMBTU) in 2025, compared to \$2.24 in 2024 and \$2.53 in 2023. The Company also has exposure to the Canadian benchmark natural gas price, Alberta Energy Company (AECO), which averaged C\$1.68 per thousand cubic feet (MCF) in 2025, compared to C\$1.46 in 2024 and C\$2.64 in 2023. The Company has entered into certain forward fixed price contracts as detailed in the "[Outlook](#)" section beginning on page [52](#) and spot contracts providing exposure to other market prices at specific sales points such as Malin (Oregon, U.S.) and Dawn (Ontario, Canada).

Lower prices, should they occur, will materially and adversely affect our results of operations, cash flows and financial condition. Lower oil and natural gas prices could result from, among other things, increased exports from producers in Venezuela, Russia or the Middle East following resolution of conflicts or political instability in such regions. Lower oil and natural gas prices could reduce the amount of oil and natural gas that the Company can economically produce, resulting in a reduction in the proved oil and natural gas reserves we could recognize, which could impact the recoverability and carrying value of our assets. The Company cannot predict how changes in the sales prices of oil and natural gas will affect the results of operations in future periods.

Lower oil and natural gas prices adversely affect the Company in several ways:

- Lower sales value for the Company's oil and natural gas production reduces cash flows and net income.
- Lower cash flows may cause the Company to reduce its capital expenditure program, thereby potentially restricting its ability to grow production and add proved reserves.

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Item 1A. Risk Factors - Continued

- Lower oil and natural gas prices could lead to impairment charges in future periods, therefore reducing net income.
- Reductions in oil and natural gas prices could lead to reductions in the Company's proved reserves in future years. Low prices could make a portion of the Company's proved reserves uneconomic, which in turn could lead to the removal of certain of the Company's year-end reported proved oil reserves in future periods. These reserve reductions could be significant.
- Lower oil and natural gas prices could lead to an inability to access, renew, or replace credit facilities, and could also impair access to other sources of funding as these mature, potentially negatively impacting our liquidity.
- Lower prices for oil and natural gas could cause the Company to lower its dividend because of lower cash flows.

See [Note K](#) for additional information on the derivative instruments used to manage certain risks related to commodity prices.

Murphy's commodity price risk management may limit the Company's ability to fully benefit from potential future price increases for oil and natural gas.

The Company, from time to time, enters into various contracts to protect its cash flows against lower oil and natural gas prices. To the extent that the Company enters into these contracts and in the event that prices for oil and natural gas increase in future periods, the Company may not fully benefit from the price improvement on all production. See [Note K](#) for additional information on the derivative instruments used to manage certain risks related to commodity prices.

Operational Risk Factors

Murphy operates in highly competitive environments which could adversely affect it in many ways, including its profitability, cash flows and its ability to grow.

Murphy operates in the oil and natural gas industry and experiences competition from other oil and natural gas companies, which include major integrated oil companies, independent producers of oil and natural gas, and state-owned foreign oil companies. Many of the major integrated and state-owned oil companies and some of the independent producers that compete with the Company have substantially greater resources than Murphy.

In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Within the industry, Murphy competes for, among other things, valuable acreage positions, exploration licenses, drilling equipment and talent.

Exploration drilling results can significantly affect the Company's operating results.

The Company drills exploratory wells which subject its E&P operating results to exposure to dry hole expense, which has in the past, and may in the future, adversely affect our results of operations. The Company plans to continue assessing exploration activities as part of its overall strategy. In 2025, the Company participated in five exploration wells. The Lac Da Hong-1X (Pink Camel), Block 15-1/05 and the Hai Su Vang-2X (Golden Sea Lion), Block 15-2/17 exploration wells, in Vietnam, resulted in commercial discoveries, while the Civette-1X (Block CI-502) exploration well, in Côte d'Ivoire, did not encounter commercial hydrocarbons. Subsequent to year end, the Banjo #1 (Mississippi Canyon 385) and Cello #1 (Mississippi Canyon 385) exploration wells, in the Gulf of America, resulted in commercial discoveries. The Company's 2026 exploration and appraisal program capital expenditures guidance of \$320 million includes drilling three wells in Vietnam and two wells in Côte d'Ivoire. One of these exploration wells in Côte d'Ivoire, Caracal-1X (Block CI-102), was completed in February 2026, and will be plugged and abandoned as a dry hole after encountering non-commercial hydrocarbon shows.

If Murphy cannot replace its oil and natural gas reserves, it may not be able to sustain or grow its business.

Murphy continually depletes its oil and natural gas reserves as production occurs. To sustain and grow its business, the Company must successfully replace the oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserves additions and production. The Company must find, acquire or develop, and produce reserves at a competitive cost to be successful in the long-term. Murphy's ability to operate profitably in the E&P business, therefore, is dependent

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Item 1A. Risk Factors - Continued

on its ability to find (and/or acquire), develop and produce oil and natural gas reserves at costs that are less than the realized sales price for these products.

Murphy's proved reserves are based on the professional judgment of its engineers and may be subject to revision.

Proved reserves of crude oil, natural gas and NGLs included in this report on pages [111](#) through [120](#) have been prepared according to the SEC guidelines by qualified company personnel or qualified independent engineers based on an unweighted average of oil and natural gas prices in effect at the beginning of each month of the respective year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable oil and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. In 2025, 95.8% of the proved reserves were audited by third-party auditors.

Murphy's actual future oil and natural gas production may vary substantially from its reported quantity of proved reserves due to a number of factors, including:

- Oil and natural gas prices which are materially different from prices used to compute proved reserves;
- Operating and/or capital costs which are materially different from those assumed to compute proved reserves;
- Future reservoir performance which is materially different from models used to compute proved reserves; and
- Governmental regulations or actions which materially impact operations of a field.

The Company's proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2025, and including noncontrolling interests, approximately 36% of the Company's crude oil proved reserves, 41% of NGL proved reserves and 47% of natural gas proved reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines and well workovers.

The discounted future net revenues from our proved reserves as reported on pages [124](#) and [125](#) should not be considered as the market value of the reserves attributable to our properties. As required by U.S. generally accepted accounting principles (GAAP), the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations.

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

Murphy is reliant on certain third party infrastructure to develop projects and operations.

The Company relies on the availability and capacity of infrastructure, such as transportation and processing facilities, and equipment that are often owned and operated by others. These third-party systems, facilities, and equipment may not always be available to the Company and, if available, may not be available at a price that is acceptable to the Company. The unavailability or high cost of such equipment or infrastructure could adversely affect our ability to establish and execute exploration and development plans within budget and on a timely basis, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our inability to access appropriate equipment and infrastructure in a timely manner and on acceptable terms may hinder our access to oil and natural gas markets or delay our oil and natural gas production.

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Item 1A. Risk Factors - Continued

Murphy is sometimes reliant on joint venture partners for operating assets, and/or funding development projects and operations.

Certain of the Company's major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its revenue generating properties. During 2025, approximately 19% of the Company's total production was at fields operated by others, while at December 31, 2025, approximately 12% of the Company's total proved reserves were at fields operated by others.

Some of Murphy's development projects entail significant capital expenditures and have long development cycle times. As a result, the Company's partners must be able to fund their share of investment costs through the development cycle, through cash flow from operations, external credit facilities, or other sources, including financing arrangements. Murphy's partners are also susceptible to certain of the risk factors noted herein, including, but not limited to, commodity prices, fiscal regime changes, government project approval delays, regulatory changes, credit downgrades and regional conflict. If one or more of these factors negatively impacts a project operator's or partners' cash flows or ability to obtain adequate financing, or if an operator of our projects fails to adequately perform operations or fulfill its obligations under the applicable agreements, it could result in a delay or cancellation of a project, resulting in a reduction of the Company's reserves and production, which negatively impacts the timing and receipt of planned cash flows and expected profitability.

Murphy's business is subject to operational hazards, severe weather events, physical security risks and risks normally associated with the E&P of oil and natural gas, which could become more significant as a result of climate change.

The Company operates in a variety of locales, including urban, remote, and sometimes inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes (and other forms of severe weather), mechanical equipment failures, industrial accidents, fires, explosions, acts of war, civil unrest, piracy and acts of terrorism could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, personal injury (including death), and property damages for which the Company could be deemed to be liable and which could subject the Company to substantial fines and/or claims for punitive damages. This risk extends to actions and operational hazards of other operators in the industry, which may also impact the Company.

The location of many of Murphy's key assets causes the Company to be vulnerable to severe weather, including hurricanes, tropical storms and extreme temperatures. Many of the Company's offshore fields are in the Gulf of America, where hurricanes and tropical storms can lead to shutdowns and damages. The U.S. hurricane season runs from June through November. Moreover, scientists have predicted that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that increase significant weather events, such as increased frequency and severity of storms, droughts, floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Although the Company maintains insurance for such risks, due to policy deductibles and possible coverage limits, weather-related risks to our operations are not fully insured. In addition, the physical effects of climate change may generally result in reduced availability of relevant insurance coverage on the market. For additional details on insurance, see "Risk Factors - General Risk Factors - Murphy's insurance may not be adequate to offset costs associated with certain events, and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase."

In addition, certain customer and supplier assets, such as storage terminals, processing facilities, refineries and pipelines, are located in areas that may be prone to severe weather events, including hurricanes, winter storms, floods and major tropical storms, all of which may be exacerbated by climate change. Severe weather events that significantly affect facilities belonging to such customers or suppliers may reduce demand for our products and interrupt our ability to bring products to market and may therefore materially and adversely affect our results of operations, cash flows and financial condition, even if our own facilities escape significant damage.

Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas.

The Company's onshore North America oil and natural gas production is dependent on a technique known as hydraulic fracturing whereby water, sand and certain chemicals are injected into deep oil and natural gas bearing reservoirs in North America. This process occurs thousands of feet below the surface and creates fractures in the rock formation within the reservoir which enhances migration of oil and natural gas to the wellbore.

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Item 1A. Risk Factors - Continued

The risks associated with hydraulic fracturing operations include, but are not limited to, underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or groundwater contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or groundwater contamination resulting from hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses, and third-party claims alleging damages, which could adversely affect the Company's financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water; the wastewater from oil and natural gas operations is often disposed of through underground injection. Certain increased seismic activities have been linked to underground water injection. Any diminished access to water for use in the hydraulic fracturing process, any inability to properly dispose of wastewater, or any further restrictions placed on wastewater, could curtail the Company's operations due to regulatory initiatives or natural constraints such as drought or otherwise result in operational delays or increased costs.

Murphy is subject to numerous environmental, health and safety laws and regulations, and such existing and any potential future laws and regulations may result in material liabilities and costs.

The Company's operations are subject to various international, foreign, national, state, provincial and local environmental, health and safety laws, regulations, governmental actions and permit requirements, including related to the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including methane and other GHG emissions; wildlife, habitat and water protection; water access, use and disposal; the placement, operation and decommissioning of production equipment; the health and safety of our employees, contractors and communities where our operations are located, including indigenous communities; and the causes and impacts of climate change. The laws, regulations, governmental actions and permit requirements are subject to frequent change and have tended to become stricter over time and at times may be motivated by political considerations. They can impose permitting and financial assurance obligations, as well as operational controls and/or siting constraints on our business, and can result in additional capital and operating expenditures. For example, in March 2024, the EPA published New Source Performance Standards and Emissions Guidelines for the oil and gas industry regulating methane and volatile organic compounds emissions in the oil and gas industry which, among other things, requires periodic inspections to detect leaks (and subsequent repairs), places stringent restrictions on venting and flaring of methane, and establishes a program whereby third parties can monitor and report large methane emissions to the EPA. However, in December 2025, the EPA issued a final rule extending several compliance deadlines and timeframes associated with the new rules. In November 2024, the EPA published its final rule implementing a charge on large emitters of waste methane from the oil and gas sector. The charge, referred to as the WEC, is a component of the Biden Administration's Methane Emissions Reduction Program to limit methane emissions from the oil and gas industry under the IRA of 2022. In March 2025, however, this rule was disapproved by a joint Congressional resolution, and the OBBBA passed in July 2025 extended the imposition of the WEC until 2034. In addition, it is possible in the future that certain regulatory bodies such as the Railroad Commission of Texas may enact regulation that bans or reduces flaring for U.S. Onshore operations, and certain regulatory bodies in Canada may decide to revoke permits or pause the issuance of permits as a result of non-compliance with, or litigation related to, environmental, health and safety laws and regulations. Compliance with such regulations could result in capital investment or operating costs which would reduce the Company's net cash flows and profitability.

Murphy also could be subject to strict liability for environmental contamination in various jurisdictions where it operates, including with respect to its current or former properties, operations and waste disposal sites, or those of its predecessors. Contamination has been identified at some locations, and the Company has been required, and in the future may be required, to investigate, remove or remediate previously disposed wastes; or otherwise clean up contaminated soil, surface water or groundwater, address spills and leaks from pipelines and production equipment, and perform remedial plugging operations. In addition to significant investigation and remediation costs, such matters can result in fines and also give rise to third-party claims for personal injury and property or other environmental damage.

The Company primarily uses hydraulic fracturing in the Eagle Ford Shale in South Texas and in the Kaybob Duvernay and the Tupper Montney in Western Canada. Texas law imposes permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations, as well as public disclosure of certain information regarding the components used in the hydraulic fracturing process. Regulations in the provinces of

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Item 1A. Risk Factors - Continued

British Columbia and Alberta also govern various aspects of hydraulic fracturing activities under their jurisdictions. It is possible that Texas, other states in which we may conduct fracturing in the future, the U.S., Canadian provinces and certain municipalities may adopt further laws or regulations which could render the process unlawful, less effective or drive up its costs. If any such action is taken in the future, the Company's production levels could be adversely affected, or its costs of drilling and completion could increase. Once new laws and/or regulations have been enacted and adopted, the costs of compliance are appraised.

In addition, the BOEM and the BSEE have regulations applicable to lessees in federal waters that impose various safety, permitting and certification requirements applicable to exploration, development and production activities in the Gulf of America, and also require lessees to have substantial U.S. assets and net worth or post bonds or other acceptable financial assurance that the regulatory obligations will be met. These include, in the Gulf of America, well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items. Under applicable requirements, BOEM evaluates the financial strength and reliability of lessees and operators active on the U.S. Outer Continental Shelf. If the BOEM determines that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance.

In addition, various executive orders by the Biden Administration and the Department of Interior over the course of 2021 regarding a temporary suspension of normal-course issuance of permits for fossil fuel development on federal lands and a pause on new oil and natural gas leases on public lands and offshore waters, and the Secretary of the Interior's overhaul of permitting and leasing regulations and rates, finalized in April 2024, could adversely impact Murphy's operations. While certain aspects of the April 2024 final rule remain in effect, the OBBBA reversed the increases to royalty rates and increased U.S. lease sales both onshore and offshore. Further in May 2025, the Department of Interior announced a policy update designed to expedite oil and gas leasing on onshore public lands. These developments demonstrate the uncertainty regarding the regulation of oil and natural gas related to shifts in political power in the U.S. For further details, see "Risk Factors - General Risk Factors - Murphy's operations and earnings have been and will continue to be affected by domestic and worldwide political developments."

We face various risks associated with increased activism against, or change in public sentiment for, oil and natural gas exploration, development, and production activities and sustainability considerations, including climate change and the transition to a lower carbon economy.

Opposition toward oil and natural gas drilling, development, and production activity has grown globally. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and nongovernmental organizations and other stakeholders regarding safety, human rights, climate change, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development, onshore hydraulic fracturing, and construction of pipelines for oil and natural gas.

Activism may continue to increase regardless of the U.S. Administration's environmental and climate change executive orders described earlier in this Form 10-K report. Our need to incur costs associated with responding to these initiatives or complying with any new legal requirements resulting from these activities that are substantial and not adequately provided for could have a material adverse effect on our business, financial condition and results of operations. In addition, a change in public sentiment regarding the oil and natural gas industry could result in a reduction in the demand for our products or otherwise affect our results of operations or financial condition.

We may face increased scrutiny from investors and other stakeholders related to our sustainability activities, including the goals, targets and objectives we announce, our methodologies and timelines for pursuing them and related disclosures. If our sustainability practices do not meet investor or other stakeholder expectations and standards, which continue to evolve, our reputation, our ability to attract or retain employees and our attractiveness as an investment or business partner could be negatively affected. Similarly, our failure or perceived failure to pursue or fulfill our sustainability-focused goals, targets and objectives, to comply with ethical, environmental or other standards, regulations or expectations or to satisfy various reporting standards with respect to these matters, within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and private litigation. In recent years, certain stakeholders and regulators have also proposed "anti-ESG" policies, legislation or initiatives. This

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Item 1A. Risk Factors - Continued

divergence in stakeholder expectations could expose us to reputational risks and potentially disrupt relationships with certain stakeholders.

While the Company has been named a co-defendant with other oil and natural gas companies in lawsuits related to climate change, these lawsuits have not resulted in, and are not currently expected to result in, material liability for the Company. Depending on the evolution of laws, regulations and litigation outcomes relating to climate change, there can be no guarantee that climate change litigation will not in the future materially adversely affect our results of operations, cash flows and financial condition. For further details on risks related to legal proceedings more generally, see "Risk Factors - General Risk Factors - Lawsuits against Murphy and its subsidiaries could adversely affect its operating results."

Financial Risk Factors

Capital financing may not always be available to fund Murphy's activities; and interest rates could impact cash flows.

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding requirements may not always coincide, and the levels of cash flow generated by operations may not fully cover capital funding requirements, especially in periods of low commodity prices. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company periodically renews these financing arrangements based on foreseeable financing needs or as they expire. Subsequent to year end, in January 2026, the Company entered into an amendment (the "Second Amendment") to its credit agreement governing a \$2.00 billion senior unsecured guaranteed revolving credit facility (Amended RCF) with a maturity date in January 2031. As of December 31, 2025, the Company had \$100 million outstanding borrowings under the previous senior unsecured guaranteed revolving credit facility (RCF). See [Note F](#) for further details on the RCF.

The Company's ability to obtain additional financing is affected by a number of factors, including the market environment, our operating and financial performance, investor sentiment, our ability to incur additional debt in compliance with agreements governing our outstanding debt, and the Company's credit ratings. A ratings downgrade could materially and adversely impact the Company's ability to access debt markets, increase the borrowing cost under the Company's credit facility and the cost of any additional indebtedness we incur, and potentially require the Company to post additional letters of credit or other forms of collateral for certain obligations. Murphy partially manages this risk through borrowing at fixed rates wherever possible; however, rates when refinancing or raising new capital are determined by factors outside of the Company's control.

Further, changes in investors' sentiment or view of risk of the E&P industry, including as a result of concerns over climate change, could adversely impact the availability of future financing. Specifically, certain financial institutions (including certain investment advisors and sovereign wealth, pension and endowment funds), in response to concerns related to climate change and the requests and other influence of environmental groups and similar stakeholders, have elected to shift some or all of their investments away from fossil fuel-related sectors, and additional financial institutions and other investors may elect to do likewise in the future. As a result, fewer financial institutions and other investors may be willing to invest in, and provide capital to, companies in the oil and natural gas sector, which, in turn, could adversely impact our cost of capital.

Since 2022, the Company undertook several actions to reduce overall debt. Murphy plans to continue with the Company's deleveraging initiatives, but there can be no assurance that these efforts will be successful and, if not, the Company's financial conditions and prospects could be adversely affected. See [Note F](#) for information regarding the Company's outstanding debt as of December 31, 2025.

We may be unable to meet our capital allocation plan of returning a percentage of adjusted free cash flow (FCF) to shareholders through share repurchases and potential dividend increases, which could decrease expected returns on an investment in our common stock.

Our capital allocation plan includes returning a percentage of adjusted FCF to shareholders through share repurchases and potential dividend increases. We may, from time to time, redeem, repurchase, retire or otherwise acquire our outstanding debt through privately negotiated transactions, open market purchases, redemptions, tender offers or otherwise, but we are under no obligation to do so. There can be no assurance

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Item 1A. Risk Factors - Continued

that we will seek to do any of the foregoing or that we will be able to do any of the foregoing on terms acceptable to us or at all.

In connection with our capital allocation plan, the Board authorized a share repurchase program, as described in this Form 10-K report. Share repurchases and dividends are authorized and determined by the Board at its sole discretion and depend upon a number of factors, including available liquidity, market conditions, applicable legal requirements and other factors. We can provide no assurance that we will make share repurchases or pay dividends in accordance with our capital allocation plan, or at all. Any elimination of, or downward revision in, our share repurchase program, dividend payment plans, or capital allocation plan could have an adverse effect on the market price of our common stock.

Meeting our capital allocation plan strategy requires us to generate consistent adjusted FCF and have available capital in the years ahead in an amount sufficient to enable us to maintain a conservative capital structure and liquidity position and invest in organic and inorganic growth, as well as to return a significant portion of the cash generated to shareholders through share repurchases and potential dividend increases. The amount of adjusted FCF returned in any quarter during the year may vary and may be more or less than our capital allocation plan. We may not meet this goal if we use our available cash to satisfy other priorities, if we have insufficient funds available to repurchase shares or pay dividends, or if the Board determines to change or discontinue share repurchases or dividend payments.

Murphy's operations could be adversely affected by changes in foreign exchange rates.

The Company's worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company's business is transacted in U.S. dollars, and therefore the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all Canadian operations. This exposure to currencies other than the U.S. dollar functional currency can lead to impacts on consolidated financial results from foreign currency translation. On occasions, the Canadian business may hold assets or incur liabilities denominated in a currency which is not Canadian dollars which could lead to exposure to foreign exchange rate fluctuations. The Company operates in various regions around the world which inherently introduces exposure to changes in foreign exchange rates when transacting in local currencies. See also [Note K](#) for additional information on derivative contracts.

The costs and funding requirements related to the Company's retirement plans are affected by several factors.

A number of actuarial assumptions impact funding requirements for the Company's retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make more significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its Consolidated Balance Sheets.

Murphy has limited control over supply chain costs.

The Company often experiences pressure on its operating and capital expenditures in periods of strong crude oil and natural gas prices because an increase in E&P activities due to high oil and natural gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and natural gas industry. In addition, periods of inflationary pressure in the wider economy, as seen during 2022, can lead to a similar increase in the cost of goods and services for the Company. Further, from time to time, Murphy will seek to enter new commitments, exercise options to extend contracts and retender contracts for rigs and other industry services which could expose Murphy to the impact of higher prices.

The Company is exposed to credit risks associated with (i) sales of certain of its products to customers, (ii) joint venture partners and (iii) other counterparties.

Murphy is exposed to credit risk in three principal areas:

- Accounts receivable credit risk from selling its produced commodity to customers;
- Joint venture partners related to certain oil and natural gas properties operated by the Company that may not be able to meet their financial obligation to pay for their share of capital and operating costs as they become due; and

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Item 1A. Risk Factors - Continued

- Counterparty credit risk related to forward price commodity hedge contracts to protect the Company's cash flows against lower oil and natural gas prices.

The inability of a purchaser of the Company's produced commodity, a joint venture partner of the Company, or counterparty in a forward price commodity hedge to meet their respective payment obligations to the Company could have an adverse effect on Murphy's future earnings and cash flows.

General Risk Factors

We face various risks related to health epidemics, pandemics and similar outbreaks, which may have material adverse effects on our business, financial position, results of operations and/or cash flows.

The future impact of any health epidemic, pandemic (such as COVID-19) or similar outbreak cannot be predicted, and any resurgence of disease may cause additional volatility in commodity prices. See "Risk Factors - Price Risk Factors - Volatility in the global prices of oil and natural gas can significantly affect the Company's operating results, cash flows and financial condition."

If significant portions of our workforce are unable to work effectively, including because of illness, quarantines, government actions, facility closures or other restrictions in connection with an epidemic, pandemic or similar outbreak, our operations will likely be impacted and our ability to produce oil and natural gas will likely decrease. We may be unable to perform fully on our commitments, and our costs may increase as a result of such epidemic, pandemic or similar outbreak. These cost increases may not be fully recoverable or adequately covered by insurance.

In addition, an epidemic, pandemic or similar outbreak could also cause disruption in our supply chain; cause delay or limit the ability of vendors and customers to perform, including in making timely payments to us; and cause other unpredictable events.

We cannot predict the impact of an epidemic, pandemic or similar outbreak. The extent to which any such epidemics, pandemics or similar outbreaks may impact our results will depend on future developments, including, among other factors, the duration and spread of the virus and its variants, availability, acceptance and effectiveness of vaccines along with related travel advisories, quarantines and restrictions, the recovery time of the disrupted supply chains and industries, the impact of labor market interruptions, and the impact of government interventions.

Changes in U.S. and international tax rules and regulations, or interpretations thereof, may materially and adversely affect our cash flows, results of operations and financial condition.

We are subject to income- and non-income-based taxes in the U.S. under federal, state and local jurisdictions and in the foreign jurisdictions in which we operate. Tax laws and regulations, or their interpretation, and administrative practices in various jurisdictions may be subject to significant change, with or without advance notice, due to economic, political and other conditions, and significant judgment is required in evaluating and estimating our provision and accruals for these taxes. Our tax liabilities could be affected by numerous factors, such as changes in tax, accounting and other laws, regulations, administrative practices, principles and interpretations, the mix and level of earnings in a given taxing jurisdiction or our ownership or capital structure. In recent years, multiple domestic and international tax proposals have been introduced that, if enacted into law would impose greater tax burdens on certain multinational enterprises. For example, the Organization for Economic Co-operation and Development (OECD) continues to advance proposals or guidance in international taxation, including the establishment of a global minimum tax on certain multinational enterprises, also known as Pillar Two. In June 2025, the U.S. reached an understanding with the Group of Seven (G7) members that the U.S. would remove a proposed retaliatory tax from the OBBBA in exchange for an exclusion of U.S. parented groups from certain aspects of Pillar Two. This understanding was non-binding and included only the G7 states. However, the OECD released significant administrative guidance on January 5, 2026, which is intended to resolve uncertainty regarding how Pillar Two will apply to U.S. parented groups. In this regard, the administrative guidance introduced a safe harbor that should effectively deem the U.S. tax system to be compliant with Pillar Two and therefore exempt U.S. parented groups from the scope of certain taxes, which should simplify ongoing compliance for affected enterprises. While we do not currently expect that Pillar Two will have a material impact on our results of operations, we continue to monitor the impact as the OECD provides additional guidance and countries implement legislation. Further, the OBBBA, enacted in the U.S. on July 4, 2025, includes a broad range of tax reform provisions affecting corporations. We continue to analyze the potential impact of the OBBBA on

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Item 1A. Risk Factors - Continued

our consolidated financial statements and to monitor guidance issued by the U.S. Department of the Treasury. It is possible that further changes may be enacted to U.S. and international tax rules and regulations, including the U.S. corporate tax system, which could have a material effect on our consolidated cash taxes in the future.

We face continued competition for talent to support our operations.

The success of our operations is dependent upon our ability to hire, develop, and retain qualified and experienced personnel. The oil and natural gas industry has experienced increased merger and acquisition activity, causing Murphy and industry peers to face heightened competition from other industries for highly sought after and transferable skill sets. In addition, changes in public sentiment towards oil and natural gas exploration, development, and production activities, along with considerations such as climate change and the transition to a lower carbon economy, may make it more difficult for us to attract such qualified personnel.

Due to significant shifts in demographics impacting the industry, such as an aging workforce and decreased enrollment in relevant fields, Murphy and industry peers are experiencing challenges in sourcing and developing a pipeline of talent for the foreseeable future, which could place our oil and natural gas exploration, development, and production activities at risk. Furthermore, the cost to attract and retain technical talent has increased in recent years due to competition and may continue to increase if the pool of available talent continues to shrink due to these demographic shifts. If there is a significant decrease in the availability of qualified talent, our operations, cash flows, and financial condition may be materially and adversely impacted.

Murphy's sensitive information, operational technology systems and critical data may be exposed to cyber threats.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct exploration, development, and production activities. We depend on these technologies to estimate quantities of oil and natural gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate internally and externally, and conduct many other business activities.

Maintaining the security of our technology and data and preventing breaches is critical to our business operation. We rely on our information systems and cybersecurity controls, training, and policies to protect and secure information technology (IT), operational technology (OT), including industrial control and supervisory control and data acquisition systems and the intellectual property, strategic plans, customer information, and personally identifiable information of both our employees and our customers contained within those information systems.

A digital infrastructure failure or a successfully executed, undetected cyberattack could significantly disrupt business operations. For example, it might lead to downtime, revenue loss, diversion of management or work force attention, and increased costs for remediation. Additionally, the compromise, theft, or unauthorized release of critical data could damage our reputation, weaken our competitive edge, negatively impact our financial stability, and expose us to legal risk in multiple jurisdictions. Due to the sophisticated nature of cyberattacks, breaches to our systems could go undetected for a prolonged period of time. Additionally, we are increasingly vulnerable to cybersecurity incidents originating within our supply chain, including compromises of third-party vendors, software providers, cloud platforms, and other external partners whose environments we depend on. Even if we successfully defend our own digital infrastructure, weaknesses or breaches within these third-party environments could compromise our data, disrupt our operations, harm our individuals, have a material financial impact on the business, or create attack paths into our systems.

As the sophistication of such cyber threats continues to evolve, including through the use of AI, we will likely be required to dedicate further resources to continue to modify or enhance our security measures, or to investigate and remediate any discovered vulnerabilities to cyberattacks. In addition, laws and regulations governing, or proposed to govern, cybersecurity, data privacy and protection and the unauthorized disclosure of confidential or protected information, including legislation in domestic and international jurisdictions, pose increasingly complex compliance challenges and potentially elevate costs, and any actual or perceived failure to comply with these laws and regulations could result in significant penalties, fines, judgments, reputational harm and legal liability. Additionally, new regulations or legislation may affect our current uses of protected information and require us to modify how we collect, protect, process, or disclose such information.

We are incorporating AI technologies into our processes, and these technologies may present business, compliance, and reputational risks.

PART I

Item 1A. Risk Factors - Continued

Our business increasingly utilizes AI and machine learning to automate certain tasks and improve our internal processes. Issues in the development and use of AI, combined with an uncertain regulatory environment, may result in new or enhanced governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability or other adverse consequences to our business operations, all of which could adversely affect our business, financial condition, and results of operations.

The use of AI can lead to unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or generating content that appears correct but is factually inaccurate, misleading, or otherwise flawed, which could expose us to risks related to inaccuracies or errors in the output of such technologies. Additionally, emerging forms of autonomous (or semi-autonomous) AI tools, such as AI agents capable of independently executing tasks, interacting with systems, or initiating actions, present additional risks such as unauthorized access, sensitive data leakage or unintended operational impacts. The use of unapproved AI tools within the organization further increases the risk of security incidents, compliance failures, and exposure of sensitive information. It is not possible to predict all of the risks related to the use of AI, machine learning, and automation, and developments in the regulatory frameworks governing the use of such technologies and in related stakeholder expectations may adversely affect our ability to develop and use such technologies or subject us to liability.

Murphy's operations and earnings have been and will continue to be affected by domestic and worldwide political developments.

From time to time, some governments intervene in the market for crude oil and natural gas produced in their countries through such actions as setting prices, determining rates of production, and controlling who may buy and sell the production.

Murphy is exposed to regulation, legislation and policies enacted by policy makers, regulators or other parties to delay or deny necessary licenses and permits to produce or transport crude oil and natural gas. As an example, the Biden Administration pursued initiatives related to environmental, health and safety standards applicable to the oil and natural gas industry. These included an executive order in January 2021 that directed the Secretary of the Interior to halt indefinitely new oil and natural gas leases on federal lands and offshore waters pending a since-completed review by the Secretary of the Interior of federal oil and natural gas permitting and leasing practices; however, a June 2021 preliminary injunction in the U.S. District Court for the Western District of Louisiana barred the implementation of the pause in new federal oil and natural gas leases. This executive order also set forth other initiatives and goals, including procurement of carbon pollution-free electricity, elimination of fossil fuel subsidies, a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050. Another executive order from January 2021 called for a climate change-focused review of regulations and other executive actions promulgated, issued or adopted during the prior presidential administration. In August 2022, the IRA of 2022 was passed by the U.S. Congress and included provisions which required the Department of Interior to hold previously announced offshore lease sales in the Gulf of America and Alaska within two years. However, on December 14, 2023, the Secretary of the Interior approved the 2024-2029 National Outer Continental Shelf Oil and Gas Leasing Program, which contemplates only three potential oil and natural gas lease sales in the Gulf of America through 2029. These Biden Administration policies have largely been overturned by President Trump's 2025 executive orders promoting American energy dominance. The OBBBA replaced the Biden Administration's five-year offshore leasing plan with at least 30 region-wide sales in the Gulf of America between December 2025 and March 15, 2040, reversed the increases to the Bureau of Land Management's royalty rates, which were raised under the IRA, and increased U.S. lease sales both onshore and offshore. In May 2025, the Department of Interior announced an update to its policy to expedite oil and gas leasing on onshore public lands. These developments demonstrate the uncertainty that can arise from the U.S. Administration's approach to oil and natural gas leasing and permitting.

In March 2024, the SEC adopted rules requiring disclosure of a wide range of climate change-related information, including, among other things, companies' climate change risk management; short-, medium-, and long-term climate-related financial risks; and disclosure of Scope 1 and Scope 2 emissions. Similar laws and regulations regarding climate change-related disclosures have been proposed or enacted in other jurisdictions, including California and the European Union. The SEC's climate disclosure rules have been stayed pending legal challenges and further action by the SEC, but implementation of the rules as finalized could be costly and time consuming.

PART I

Item 1A. Risk Factors - Continued

These actions and any future changes to applicable environmental, health and safety, regulatory and legal requirements promulgated by the U.S. Administration and Congress may restrict our access to additional acreage and new leases in the Gulf of America or lead to limitations or delays on our ability to secure additional permits to drill and develop our acreage and leases or otherwise lead to limitations on the scope of our operations, or may lead to increases to our compliance costs. The potential impacts of these changes on our future financial condition, results of operations or cash flows cannot be predicted.

Prices and availability of crude oil, natural gas and refined products could be influenced by political factors and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include expropriation, tax law changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and natural gas leases, restrictions on drilling and/or production, tariffs, restraints and controls on imports and exports, safety, and relationships between employers and employees. For example, in 2025, the Trump Administration announced additional tariffs on goods from all countries pursuant to the International Emergency Economic Powers Act. These tariffs were later found to have exceeded presidential authority and were invalidated by the courts. Following such ruling, President Trump implemented a 150-day "global tariff" of 10% effective February 24, 2026, using presidential powers under the Trade Act of 1974, and indicated a desire to increase such "global tariff" to 15% and to seek to extend such tariffs under other statutes. Such tariffs may put upwards pressure on the prices of goods and services across the jurisdictions in which we operate. In addition, the scope and durability of existing and future tariff measures remain uncertain. We cannot predict future changes to trade policy, including whether existing or future tariff policies will be maintained or modified or whether the entry into new trade agreements will occur, nor can we predict the effects that any such changes would have on our business. Changes in trade policy have resulted and could again result in reactions from trading partners, including adopting responsive trade policies making it more difficult or costly for us to conduct business across the jurisdictions in which we operate. These changes, and any resulting negative sentiments or retaliatory trade practices, could materially and adversely affect our business, financial condition, results of operations and liquidity. Governments could also initiate regulations concerning matters such as currency fluctuations, currency conversion, protection and remediation of the environment, and concerns over the possibility of global warming caused by the production and use of hydrocarbon energy. As of December 31, 2025, 1.8% of the Company's proved reserves, as defined by the SEC, were located in countries other than the U.S. and Canada.

A number of non-governmental entities routinely attempt to influence industry members and government energy policy in an effort to limit industry activities, such as hydrocarbon production, drilling and hydraulic fracturing with the desire to minimize the emission of GHGs such as carbon dioxide, which may harm air quality, and to restrict hydrocarbon spills, which may harm land and/or groundwater.

Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act and other similar anti-corruption compliance statutes in the jurisdictions in which we operate.

It is not possible to predict the actions of governments, including the U.S. Administration, and hence the impact on Murphy's future operations and earnings.

Murphy's insurance may not be adequate to offset costs associated with certain events, and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase.

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately \$500 million per occurrence and in the annual aggregate. Generally, this insurance covers various types of third-party claims related to personal injury, death and property damage, including claims arising from "sudden and accidental" pollution events. The Company also maintains insurance coverage for property damage and well control with a limit of \$450 million per occurrence (\$850 million for Gulf of America claims), all or part of which could apply to certain sudden and accidental pollution events. These policies have deductibles ranging from \$10 million to \$25 million. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company's financial condition and results of operations in the future.

Murphy could face long-term challenges to the fossil fuels business model reducing demand and price for hydrocarbon fuels.

PART I

Item 1A. Risk Factors - Continued

Murphy's business model may come under more pressure from changing environmental and social trends and the related global demands for non-fossil fuel energy sources. This demand in alternative forms of energy may cause the price of our products to become more volatile and decline. Further, a reduction in demand for fossil fuels could adversely impact the availability of future financing. As part of Murphy's strategy review process, the Company reviews hydrocarbon demand forecasts and assesses the impact on its business model, plans and future estimates of reserves. In addition, the Company evaluates other lower-carbon technologies that could complement our existing assets, strategy and competencies as part of its long-term capital allocation strategy. The Company also has significant natural gas reserves which emit lower carbon compared to crude oil and NGLs.

The issue of climate change has caused considerable attention to be directed towards initiatives to reduce global GHG emissions. International agreements have resulted in commitments from many countries to reduce GHG emissions and have called for parties to eliminate certain fossil fuel subsidies and pursue further action on non-carbon dioxide GHGs, in addition to calls for transitioning away from fossil fuels and a pledge to achieve near-zero methane emissions by a specified future date. In addition, future presidential administrations could issue various executive orders that may result in additional laws, rules and regulations in the area of climate change.

It is possible that international agreements, presidential executive orders, and other such initiatives, including foreign, federal, and state laws, rules, or regulations related to GHG emissions and climate change, may reduce the demand for crude oil and natural gas globally. In addition to regulatory risk, other market and social initiatives such as public and private efforts that aim to subsidize the development of non-fossil fuel energy sources, may reduce the competitiveness of carbon-based fuels, such as oil and natural gas. While the magnitude of any reduction in hydrocarbon demand is difficult to predict, such a development could adversely impact the Company and other companies engaged in the E&P business. With or without renewable-energy subsidies, the unknown pace and strength of technological advancement and adoption of non-fossil-fuel energy sources creates uncertainty about the timing and pace of effects on our business model. The Company continually monitors global climate change initiatives and plans accordingly based on its assessment of the effects of such initiatives on its business.

Lawsuits against Murphy and its subsidiaries could adversely affect its operating results.

The Company or certain of its consolidated subsidiaries are involved in numerous legal proceedings, including lawsuits for alleged personal injuries, environmental and/or property damages, climate change and other business-related matters. Certain of these claims may take many years to resolve through court and arbitration proceedings or negotiated settlements. In the opinion of management and based upon currently known facts and circumstances, the currently pending legal proceedings are not expected, individually or in the aggregate, to have a material adverse effect upon the Company's operations or financial condition.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the SEC as of December 31, 2025.

Item 1C. CYBERSECURITY

Murphy's cybersecurity environment and risk strategy is broadly managed by the Company's IT group, which oversees the Company's IT and OT infrastructure. Within the IT group, the Murphy Cybersecurity Team (MCT) is specifically responsible for monitoring and managing security of the enterprise IT and OT network and systems, including developing and deploying administrative policies, technical controls, and safety protocols necessary to prevent unauthorized access, theft, damage, or loss of Company data or systems. All members of the MCT hold globally-recognized security certifications and have wide-ranging experience in cybersecurity matters. The Incident Management Team (IMT) is responsible for responding to active security threats and incidents as they occur. The Chief Information Officer (CIO) oversees the IT group and, either personally or through a designated representative, serves as a member of the IMT. The CIO reports directly to the Chief Technology Officer who briefs the executive leadership team, and the Audit Committee of the Board regarding cybersecurity risks, strategy, and management at least annually. The Audit Committee is ultimately responsible for overseeing cybersecurity strategy and ensuring that management has sufficient resources, programs, and processes in

PART I

Item 1C. Cybersecurity - Continued

place to identify, evaluate, manage, and mitigate relevant cybersecurity risks to which Murphy is exposed and to implement processes and programs to manage cybersecurity risks and mitigate any incidents. The Audit Committee also reports material cybersecurity risks to the Board as appropriate. We believe this visibility and oversight structure allows the Board and executive leadership team to make timely, data-driven decisions ensuring that Murphy, its employees, investors, and partners are adequately protected.

Murphy considers its cybersecurity risk management framework to be a core component of its overall enterprise risk management system. The cybersecurity risk management framework directly aligns with the National Institute of Standards and Technology Cybersecurity Framework and involves regular review and update of security policies and procedures; leverage of industry-leading technologies focused on continuously monitoring, analyzing, and defending against intrusions; regular testing of such technologies and other controls; periodic simulations of security incidents; and constant monitoring of the broader cybersecurity environment for new and emerging threats. The Company also requires employees to attend regular cybersecurity training and education to mitigate cybersecurity risks. To remain informed of the cybersecurity landscape, the Company collaborates with peers, third-party advisors, industry groups and policymakers.

Murphy engages cybersecurity assessors, consultants, our internal auditors, and other third parties both periodically and as appropriate when cyber threats are identified. Murphy utilizes these consultants to perform forensic analysis of data published by threat actors, to monitor and scan Murphy's systems for threat vectors, and to consult on emerging cybersecurity environment topics.

In addition to monitoring its own IT systems, Murphy also has processes in place to identify cybersecurity risks and threats associated with third party service providers and partners. These processes include conducting vendor due diligence and risk assessments, participating in industry information sharing groups, subscribing to cybersecurity notification services, and maintaining ongoing collaboration with federal agencies.

To our knowledge, Murphy has not experienced any cybersecurity incidents that have had, or are likely to have, material impacts to our business, operations, finances, or reputation.

PART I

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas properties are included in "[Item 1](#)" of this Form 10-K report beginning on page [1](#). Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the "[Supplemental Oil and Natural Gas Information](#)" section of this Annual Report on Form 10-K on pages [111](#) to [126](#) and in [Note D](#) beginning on page [79](#).

Item 3. LEGAL PROCEEDINGS

Discussion of the Company's legal proceedings are included in [Note Q](#) beginning on page [101](#).

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

PART I

Information about our Executive Officers

The present corporate office, length of service in office, and age at February 1, 2026, for each of the Company's executive officers are reported in the following listing. Executive officers are elected annually but may be removed from office at any time by the Board.

Eric M. Hambly - Age 51; President and Chief Executive Officer since January 2025. Mr. Hambly served as President and Chief Operating Officer from February 2024 to December 2024. Mr. Hambly also served as Executive Vice President, Operations from 2020 to 2024 and Executive Vice President, Onshore from 2018 to 2020.

Thomas J. Mireles - Age 53; Executive Vice President & Chief Financial Officer since 2022. Mr. Mireles was Senior Vice President, Technical Services from 2018 to 2022. Mr. Mireles also served as the Senior Vice President, Eastern Hemisphere of Murphy Exploration & Production Company from 2016 to 2018.

E. Ted Botner - Age 61; Executive Vice President, General Counsel & Corporate Secretary since February 2024. Mr. Botner served as Senior Vice President, General Counsel & Corporate Secretary from 2020 to 2024. He also served as Vice President, Law & Corporate Secretary from 2015 to 2020.

Daniel R. Hanchera - Age 68; Senior Vice President, Business Development since 2022. Mr. Hanchera served as Senior Vice President, Business Development of Murphy Exploration & Production Company from 2014 to 2022.

Maria A. Martinez - Age 51; Senior Vice President, Human Resources, Administration and Communications since August 2025. Ms. Martinez was Vice President, Human Resources and Administration from 2018 to August 2025.

Atif Riaz - Age 38; Vice President, Investor Relations & Treasurer since November 2025. Mr. Riaz was Vice President & Treasurer from August 2025 to October 2025. He also served as Chief Information & Digital Officer from October 2021 to August 2025 and as General Manager, Process Transformation from 2019 to 2021.

Paul D. Vaughan - Age 59; Vice President & Controller since 2022. Mr. Vaughan was Vice President & Controller, U.S., Central and South America of Murphy Exploration & Production Company from 2017 to 2022.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER

PURCHASES OF EQUITY SECURITIES

The Company's common stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 1,808 stockholders of record as of January 31, 2026.

Information on dividends per share by quarter for 2025 and 2024 are reported on page [127](#) of this Form 10-K report. Dividends are authorized and determined by the Board at its sole discretion and depend upon a number of factors, including available liquidity, market conditions, applicable legal requirements and other factors.

Information concerning securities authorized for issuance under equity compensation plans will be disclosed in our definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2026.

Issuer Purchases of Equity Securities

The Board has authorized a share repurchase program whereby the Company can repurchase up to \$1,100.0 million of its common stock. Pursuant to the share repurchase program, the Company may repurchase shares through open market purchases, privately negotiated transactions and other means in accordance with federal securities laws. This repurchase program has no time limit and may be suspended or discontinued completely at any time without prior notice as determined by the Company at its discretion and dependent upon a variety of factors.

During the three months ended December 31, 2025, the Company did not repurchase any shares of its common stock. Since the inception of the share repurchase program through the end of the fourth quarter of 2025, the Company has repurchased 15.0 million shares of its common stock in open-market transactions. As of December 31, 2025, the Company had \$550.1 million of its common stock remaining available to repurchase under the program.

PART II

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

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

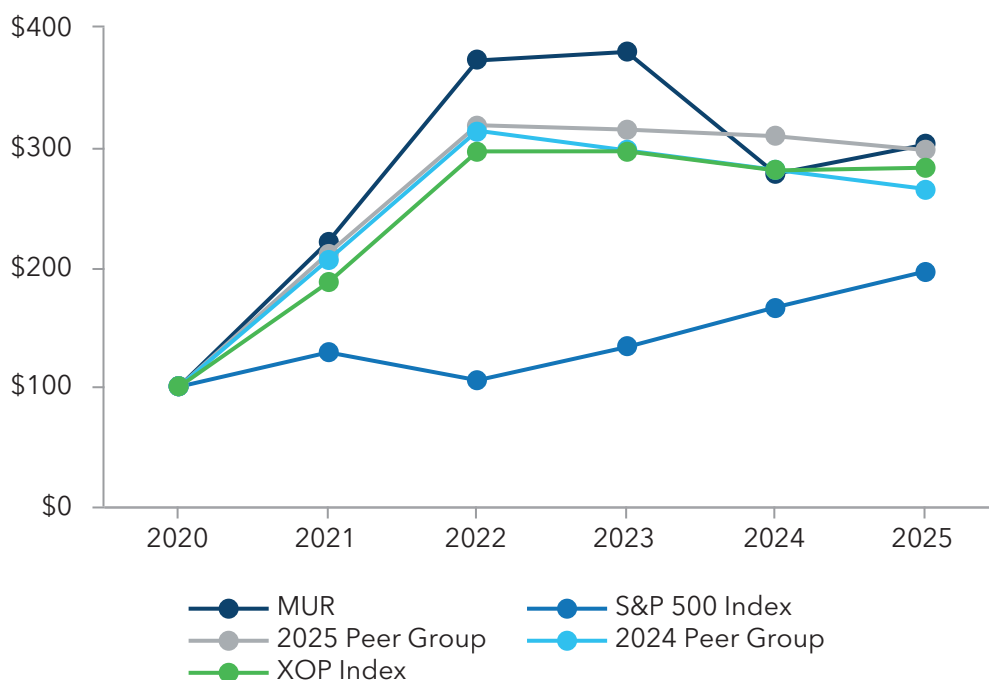
The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a \$100 investment was made on December 31, 2020 in the Company, the Standard & Poor's 500 Stock Index (S&P 500 Index), the S&P Oil & Gas Exploration & Production Select Industry Index (XOP Index) and the Company's peer group. XOP Index reports a comprehensive view of the oil and natural gas E&P segment of the S&P Total Market Index, which is more comparable for the Company than the S&P 500 Index. Our peer group for 2025 is presented in the table below. Chord Energy Corporation, Diamondback Energy, Inc., Expand Energy Corporation and Permian Resources Corporation were added to Murphy's peer group in 2025. Marathon Oil Corporation and Southwestern Energy Company were removed from Murphy's peer group in 2025. This performance information is "furnished" by the Company and is not considered as "filed" with this Form 10-K report and it is not incorporated into any document that incorporates this Form 10-K report by reference. The companies in the peer group include:

APA Corporation
Chord Energy Corporation
Civitas Resources, Inc.
Coterra Energy Inc.
Devon Energy Corporation
Diamondback Energy, Inc.

Expand Energy Corporation
EOG Resources, Inc.
Kosmos Energy Ltd.
Magnolia Oil & Gas Corporation
Matador Resources Company
Ovintiv Inc.

Permian Resources Corporation
Range Resources Corporation
SM Energy Company
Talos Energy Inc.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN



	2020	2021	2022	2023	2024	2025
Murphy Oil Corporation	100	221	372	380	278	302
S&P 500 Index	100	129	105	133	166	196
2025 Peer Group	100	211	318	315	309	298
2024 Peer Group	100	206	314	297	281	265
XOP Index	100	187	297	297	281	283

PART II

Item 6. RESERVED

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

The following Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) should be read together with the consolidated financial statements and accompanying notes to consolidated financial statements, which are included in Item 8 of this Annual Report on Form 10-K. This MD&A includes forward-looking statements that involve certain risks and uncertainties. See "[Forward-Looking Statements](#)" at the end of this section and "[Risk Factors](#)" under Item 1A. Discussion and analysis of 2023 results and year-over-year comparisons between 2024 and 2023 are not included in this Form 10-K and can be found in "Item 7" of the 2024 Annual Report on Form 10-K available via the SEC's website at www.sec.gov and on our website at www.murphyoilcorp.com.

Murphy Oil Corporation is a worldwide oil and natural gas E&P company with both onshore and offshore operations and properties. The Company produces oil and natural gas primarily in the U.S. and Canada and explores for crude oil, natural gas and NGLs in targeted areas worldwide. A more detailed description of the Company's significant assets can be found in "[Item 1](#)" of this Form 10-K report.

The analysis and discussion in this section includes amounts attributable to a noncontrolling interest (NCI) in MP GOM, unless otherwise noted.

Significant Company financial and operational highlights during 2025 were as follows:

- Generated net income of \$138.8 million (\$104.2 million excluding NCI) and net cash provided by operating activities of \$1,247.8 million;
- Produced 189 thousand BOEPD (182 thousand BOEPD excluding NCI);
- Repurchased 3.6 million shares of common stock under the share repurchase program for \$100.0 million (\$100.8 million including excise taxes and fees) under the capital allocation plan¹;
- Achieved 101% (103% excluding NCI) total proved reserve replacement with year-end proved reserves of 730.0 million MMBOE (715.0 MMBOE excluding NCI);
- Closed the strategic acquisition of the Pioneer floating production, storage and offloading vessel (FPSO) in the Gulf of America for a gross purchase price of \$125.0 million; and
- Drilled oil discoveries at the Lac Da Hong-1X (Pink Camel), Block 15-1/05 and Hai Su Vang-1X (Golden Sea Lion), Block 15-2/17 exploration wells in Vietnam.

Subsequent to year end:

- Issued \$500.0 million of 6.50% senior notes due in 2034 and used proceeds to redeem an aggregate \$227.5 million of senior notes due in 2027 and 2028;
- Upsized senior unsecured revolving credit facility from \$1.35 billion to \$2.00 billion and extended maturity from 2029 to 2031;
- Drilled oil discoveries at Cello #1 (Mississippi Canyon 385) and Banjo #1 (Mississippi Canyon 385) exploration wells in the Gulf of America, and announced a dry hole at Civette-1X (Block CI-502) and Caracal-1X (Block CI-102) in Côte d'Ivoire; and
- Increased the quarterly cash dividend to \$0.35 per share, which on an annualized basis would be \$1.40 per share.

¹ Details of the capital allocation plan can be found as part of the Company's [Form 8-K](#) filed on August 4, 2022 and [Form 8-K](#) filed on August 8, 2024. The Company's Board of Directors has authorized a share repurchase program whereby the Company can repurchase up to \$1,100.0 million of the Company's common stock.

PART II

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

Murphy's continuing operations generate revenue by producing oil and natural gas in the U.S. and Canada and then selling these products to customers. The Company's revenue is affected by the prices of oil and natural gas. In order to make a profit and generate cash in its E&P business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products and expenses related to exploration, administration and capital borrowing from lending institutions and note holders.

For the year ended December 31, 2025, the Company's net income from continuing operations was \$138.3 million, a decrease of \$351.0 million compared to 2024. Lower net income from continuing operations was largely driven by lower revenues and other income (\$309.7 million), higher depreciation, depletion and amortization expense (DD&A) (\$112.0 million), higher other losses (\$93.2 million), higher impairment expense (\$52.1 million) and higher selling and general expenses (\$27.2 million). These items were partially offset by lower lease operating expenses (\$171.7 million), lower income tax expense (\$33.7 million), and lower exploration expenses (\$21.9 million).

Lower revenues from production were primarily driven by lower average oil prices and lower volumes in the Gulf of America due to downtime and the natural decline of new wells, and was partially offset by increased production in the Eagle Ford Shale due to new wells and improved performance, as well as higher realized natural gas prices in Canada, at the Tupper Montney. Higher DD&A was primarily due to increased production and higher rates in the Eagle Ford Shale, and higher rates in the Gulf of America, and was partially offset by lower production in the Gulf of America. Higher other losses were mainly due to unrealized losses on foreign exchange related to our Canada business and were partially offset by lower interest expenses due to no debt repayment fees in the current year. Impairment expense of \$115.0 million in 2025 was related to the impairment of the Dalmatian property due to reserve reductions, as certain projects in the field were less competitive for capital allocation. Higher selling and general expenses were due to higher salary and compensation costs in 2025. Lower lease operating expenses were due to lower workovers in the current year, combined with lower operating costs related to the purchase of the Pioneer FPSO. Lower income tax expense was primarily attributable to lower taxable income and was partially offset by the non-recurrence of an income tax deduction that occurred in 2024 relating to prior years' Australian exploration spend. Lower exploration expenses were due to lower dry hole costs in the current period, which related to the Civette-1X (Block CI-502) exploration well in Côte d'Ivoire, and was partially offset by higher exploration, geological, geophysical and other costs related to the Company's U.S. Offshore and Côte d'Ivoire exploration programs.

For the year ended December 31, 2025, total hydrocarbon production was 188,682 BOEPD, an increase of 2% compared to 2024. The increase was principally due to higher production in the Eagle Ford Shale and Canada Onshore and was partially offset by lower production in the Gulf of America. Increased production in the Eagle Ford Shale was driven primarily by the performance of new wells online in the current year at Karnes and Catarina. Higher production in Canada Onshore related to better well performance at the Tupper Montney. Lower production in the Gulf of America related to planned and unplanned downtime and was partially offset by new wells online.

PART II

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

Results of Operations

Murphy's Net income (loss) by type of business and geographic segment is presented below:

<i>(Millions of dollars)</i>	2025	2024	2023
Exploration and production			
United States	\$ 308.5	\$ 561.9	\$ 905.1
Canada	54.8	49.0	41.6
Other International	(66.6)	(12.5)	(65.5)
Total exploration and production	296.7	598.4	881.2
Corporate and other	(158.4)	(109.1)	(156.0)
Income from continuing operations	138.3	489.3	725.2
Income (loss) from discontinued operations ¹	0.5	(2.8)	(1.5)
Net income including noncontrolling interest	138.8	486.5	723.7
Net income attributable to noncontrolling interest	34.6	79.3	62.1
Net income attributable to Murphy	\$ 104.2	\$ 407.2	\$ 661.6

¹ The Company has presented its former U.K. and U.S. refining and marketing operations as discontinued operations in its consolidated financial statements.

E&P Continuing Operations: 2025 vs 2024

The following section of E&P continuing operations excludes the Corporate segment, unless otherwise noted.

Please also refer to "[Schedule 6 - Results of Operations for Oil and Natural Gas Producing Activities](#)" in the Supplemental Oil and Natural Gas Information section for additional supporting tables.

The following is a summarized statement of operations for E&P continuing operations.

<i>(Millions of dollars)</i>	2025	2024	2023
Revenues and other income			
Revenue from production	\$ 2,689.8	\$ 3,014.9	\$ 3,376.6
Sales of purchased natural gas	—	3.7	72.2
Gain on sale of assets and other operating income	17.6	6.0	8.0
Total revenues and other income	2,707.4	3,024.6	3,456.8
Costs and Expenses			
Lease operating expenses	765.2	937.0	784.4
Severance and ad valorem taxes	39.2	39.2	42.8
Transportation, gathering and processing	199.7	210.8	233.0
Costs of purchased natural gas	—	3.1	51.7
Depreciation, depletion and amortization	969.4	856.9	850.5
Impairments of assets	115.0	62.9	—
Accretion of asset retirement obligations	57.6	52.4	46.0
Total exploration expenses, including undeveloped lease amortization	111.7	133.5	234.8
Selling and general expenses	46.2	23.8	37.7
Other	16.5	0.3	56.9
Results of operations before taxes	386.9	704.7	1,119.0
Income tax expense	90.2	106.3	237.8
Results of operations (excluding Corporate segment) ¹	\$ 296.7	\$ 598.4	\$ 881.2

¹ Includes results attributable to the noncontrolling interest in MP GOM.

PART II

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

Pricing

The following table contains the weighted average sales prices for the three years ended December 31, 2025:

	2025	2024	2023
Crude oil and condensate – dollars per barrel			
United States - Onshore	\$ 64.59	\$ 75.77	\$ 76.96
United States - Offshore ¹	65.69	76.36	77.38
Canada - Onshore ²	57.16	67.49	72.84
Canada - Offshore ²	68.77	82.22	84.20
Other ²	69.26	77.59	86.60
Natural gas liquids – dollars per barrel			
United States - Onshore	19.38	20.20	19.69
United States - Offshore ¹	20.40	23.37	21.94
Canada - Onshore ²	29.60	34.14	35.87
Natural gas – dollars per thousand cubic feet			
United States - Onshore	2.91	1.90	2.26
United States - Offshore ¹	3.75	2.40	2.78
Canada - Onshore ²	1.79	1.59	2.06

¹ Prices include the effect of the noncontrolling interest in MP GOM.

² U.S. dollar equivalent.

The following table contains benchmark prices relevant to the Company for the three years ended December 31, 2025:

<i>(Average price for the period)</i>	2025	2024	2023
Oil and NGLs			
WTI (\$/BBL)	\$ 64.81	\$ 75.72	\$ 77.62
Natural gas			
Henry Hub (\$/MMBTU)	3.54	2.24	2.53
AECO (C\$/MCF)	1.68	1.46	2.64

PART II

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

Production Volumes

The following table contains hydrocarbons produced during the three years ended December 31, 2025. For further discussion on volumes, please see "[Revenues from Production](#)" section on page [38](#).

<i>(Barrels per day unless otherwise noted)</i>	2025	2024	2023
Net crude oil and condensate			
United States - Onshore	26,186	21,151	24,070
United States - Offshore ¹	56,797	63,047	73,473
Canada - Onshore	2,958	2,868	2,937
Canada - Offshore	6,981	7,251	3,020
Other	275	219	250
Total net crude oil and condensate	93,197	94,536	103,750
Net natural gas liquids			
United States - Onshore	5,870	4,442	4,617
United States - Offshore ¹	4,436	4,544	5,924
Canada - Onshore	521	597	681
Total net natural gas liquids	10,827	9,583	11,222
Net natural gas - thousands of cubic feet per day			
United States - Onshore	33,415	25,028	25,863
United States - Offshore ¹	51,793	57,228	70,239
Canada - Onshore	422,742	398,786	369,906
Total net natural gas	507,950	481,042	466,008
Total net hydrocarbons - including noncontrolling interest ²	188,682	184,293	192,640
Noncontrolling interest			
Net crude oil and condensate - barrels per day	(5,876)	(6,358)	(6,210)
Net natural gas liquids - barrels per day	(217)	(199)	(220)
Net natural gas - thousands of cubic feet per day	(1,767)	(1,942)	(2,089)
Total noncontrolling interest ²	(6,388)	(6,881)	(6,778)
Total net hydrocarbons - excluding noncontrolling interest ²	182,294	177,412	185,862
Estimated total proved net hydrocarbon reserves - million equivalent barrels ³	730.0	729.0	739.5

¹ Includes net volumes attributable to the noncontrolling interest in MP GOM.

² Natural gas converted on an energy equivalent basis of 6:1.

³ Proved reserves at December 31, 2025, 2024 and 2023, include 15.0 MMBOE, 15.9 MMBOE and 15.5 MMBOE, respectively, attributable to NCI.

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Sales Volumes

The following table contains hydrocarbons sold during the three years ended December 31, 2025. For further discussion on volumes, please see "[Revenues from Production](#)" section on page [38](#).

<i>(Barrels per day unless otherwise noted)</i>	2025	2024	2023
Net crude oil and condensate			
United States - Onshore	26,186	21,151	24,070
United States - Offshore ¹	56,532	63,612	73,373
Canada - Onshore	2,958	2,868	2,937
Canada - Offshore	7,451	6,445	2,559
Other	226	230	349
Total net crude oil and condensate	93,353	94,306	103,288
Net natural gas liquids			
United States - Onshore	5,870	4,443	4,617
United States - Offshore ¹	4,436	4,543	5,924
Canada - Onshore	521	597	681
Total net natural gas liquids	10,827	9,583	11,222
Net natural gas - thousands of cubic feet per day			
United States - Onshore	33,415	25,028	25,863
United States - Offshore ¹	51,793	57,228	70,239
Canada - Onshore	422,742	398,786	369,906
Total net natural gas	507,950	481,042	466,008
Total net hydrocarbons - including noncontrolling interest ²	188,838	184,063	192,178
Noncontrolling interest			
Net crude oil and condensate - barrels per day	(5,837)	(6,438)	(6,200)
Net natural gas liquids - barrels per day	(217)	(198)	(220)
Net natural gas - thousands of cubic feet per day	(1,767)	(1,942)	(2,089)
Total noncontrolling interest ²	(6,349)	(6,960)	(6,768)
Total net hydrocarbons - excluding noncontrolling interest ²	182,489	177,103	185,410

¹ Includes net volumes attributable to the noncontrolling interest in MP GOM.

² Natural gas converted on an energy equivalent basis of 6:1.

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Revenues from Production

The Company's production revenues by country and product were as follows.

<i>(Millions of dollars)</i>	2025	2024	2023
Revenues from production			
United States - Oil	\$ 1,972.9	\$ 2,364.3	\$ 2,748.5
United States - Natural gas liquids	74.5	71.7	80.6
United States - Natural gas	106.5	67.8	92.7
Canada - Oil	248.8	264.8	156.7
Canada - Natural gas liquids	5.6	7.4	8.9
Canada - Natural Gas	275.8	232.3	278.2
Other - Oil	5.7	6.6	11.0
Total revenues from production	<u>\$ 2,689.8</u>	<u>\$ 3,014.9</u>	<u>\$ 3,376.6</u>

Revenues from production in 2025 decreased by \$325.1 million compared to 2024. Lower revenues were primarily driven by lower crude oil prices, as well as decreased production in the Gulf of America due to well issues at Samurai, natural decline, and downtime for maintenance at Khaleesi. These decreases were partially offset by wells online at Mormont and Neidermeyer in the Gulf of America, improved performance, new wells, and the acquisition of additional working interests in the Eagle Ford Shale, and new wells and improved performance in the Tupper Montney. Higher realized gas pricing in the period was also an offset to the decrease in revenue.

Gain on Sale of Assets and Other Operating Income

Other income was \$17.6 million in 2025, an increase of \$11.6 million compared to 2024. Higher other income was primarily the result of a gain recognized on contingent consideration related to the 2022 sale of working interests in Block CA-2 in Brunei.

Lease Operating and Transportation, Gathering and Processing Expenses

The Company's total lease operating expenses and transportation, gathering and processing expenses by geographic area were as follows.

	<i>(Millions of dollars)</i>			<i>(Dollars per equivalent barrel)</i>		
	2025	2024	2023	2025	2024	2023
Lease operating expenses						
United States - Onshore	\$ 125.5	\$ 141.9	\$ 150.3	\$ 9.15	\$ 13.02	\$ 12.48
United States - Offshore	451.6	608.0	480.4	17.78	21.38	14.46
Canada - Onshore	128.2	132.6	140.3	4.75	5.18	5.89
Canada - Offshore	57.4	52.9	11.5	21.12	22.43	12.30
Other	2.5	1.6	1.9	29.74	18.52	14.94
Total lease operating expenses	<u>\$ 765.2</u>	<u>\$ 937.0</u>	<u>\$ 784.4</u>	<u>\$ 11.10</u>	<u>\$ 13.91</u>	<u>\$ 11.18</u>
Transportation, gathering and processing						
United States - Onshore	\$ 11.0	\$ 9.6	\$ 12.7	\$ 0.81	\$ 0.88	\$ 1.05
United States - Offshore	96.0	121.3	144.3	3.78	4.27	4.34
Canada - Onshore	87.0	75.5	72.2	3.22	2.95	3.03
Canada - Offshore	5.7	4.4	3.8	2.08	1.85	4.12
Total transportation, gathering and processing	<u>\$ 199.7</u>	<u>\$ 210.8</u>	<u>\$ 233.0</u>	<u>\$ 2.90</u>	<u>\$ 3.13</u>	<u>\$ 3.32</u>

Lease operating expenses and transportation, gathering and processing expenses in 2025 decreased by \$171.8 million and \$11.1 million, respectively, compared to 2024. Lower lease operating expenses were primarily due to lower workover costs in the Gulf of America, lower operating costs as a result of the acquisition of the Pioneer

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FPSO and lower production handling fees. In the Eagle Ford Shale, lower operating costs resulted from cost-savings initiatives, including workforce reductions at the end of 2024, lower repairs and maintenance, and equipment optimizations, and were partially offset by higher volume related costs.

Depreciation, Depletion and Amortization Expense

The Company's DD&A expense by geographic area was as follows.

	<i>(Millions of dollars)</i>			<i>(Dollars per equivalent barrel)</i>		
	2025	2024	2023	2025	2024	2023
Depreciation, depletion and amortization expense						
United States - Onshore	\$ 412.3	\$ 319.9	\$ 316.7	\$ 30.02	\$ 29.36	\$ 26.29
United States - Offshore	409.8	389.3	389.3	16.13	13.69	11.72
Canada - Onshore	118.1	123.5	133.4	4.38	4.82	5.60
Canada - Offshore	26.7	22.5	8.8	9.81	9.55	9.47
Other	2.5	1.7	2.3	30.23	20.13	18.05
Total depreciation, depletion and amortization expense	<u>\$ 969.4</u>	<u>\$ 856.9</u>	<u>\$ 850.5</u>	<u>\$ 14.06</u>	<u>\$ 12.72</u>	<u>\$ 12.12</u>

DD&A in 2025 increased by \$112.5 million compared to 2024. The increase was primarily due to higher sales volumes and higher rates in the Eagle Ford Shale, higher rates in the Gulf of America, and was partially offset by lower production in the Gulf of America.

Impairment of Assets

In the third quarter of 2025, the Company recorded impairment costs in the Gulf of America totaling \$115.0 million (\$92.0 million excluding NCI), related to the partial write-down of the Dalmatian field due to reserve reductions, as certain projects in the field were less competitive for capital allocation.

In 2024, the Company recorded impairment costs for two assets in the Gulf of America, totaling \$62.9 million. In the first quarter, the Company recognized an impairment expense of \$34.5 million for the Calliope field. In the fourth quarter, an impairment expense of \$28.4 million was recorded for the Nearly Headless Nick field. Both fields were impaired as a result of operational issues that led to reserve reductions.

Exploration Expenses

The Company's exploration expenses were as follows.

	<i>(Millions of dollars)</i>		
	2025	2024	2023
Exploration expenses			
Dry holes and previously suspended exploration costs	\$ 30.1	\$ 73.2	\$ 169.8
Geological and geophysical	36.0	27.2	26.1
Other exploration	33.9	23.5	28.0
Undeveloped lease amortization	11.7	9.6	10.9
Total exploration expenses	<u>\$ 111.7</u>	<u>\$ 133.5</u>	<u>\$ 234.8</u>

Exploration expenses in 2025 decreased by \$21.8 million compared to 2024. In 2025, dry holes were related to the operated Civette-1X (Block CI-502) exploration well in Côte d'Ivoire. In 2024, dry holes and previously suspended exploration costs primarily related to the Sebastian #1 (Mississippi Canyon 387) exploration well, the non-operated Orange #1 (Mississippi Canyon 216) exploration well, and the previously suspended exploration well at Hoffe Park #1 (Mississippi Canyon 166) in the Gulf of America. The decrease due to lower dry hole costs was partially offset by increases to geological, geophysical and other exploration costs, related to the Company's Gulf of America and Côte d'Ivoire exploration programs.

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Selling and General Expenses

Selling and general expenses were \$46.2 million in 2025, an increase of \$22.4 million compared to 2024. Selling and general expenses were higher due to higher salary and long-term incentive compensation costs primarily related to a higher average share price throughout 2025.

Other Expenses

Total other losses were \$16.5 million in 2025, an increase of \$16.2 million compared to 2024. The increase was primarily due to no repeat of interest income on outstanding joint interest receivables that was received in 2024.

Income Taxes

Income taxes were \$90.2 million in 2025, a decrease of \$16.1 million compared to 2024. Lower income taxes were primarily the result of lower pretax income. This was partially offset by the non-recurrence of an income tax deduction that occurred in 2024 relating to prior years' Australian exploration spend.

Corporate: 2025 vs 2024

Corporate activities include interest expense and income, foreign exchange effects, realized and unrealized gains/losses on derivative instruments (forward swaps to hedge the price of natural gas sold) and corporate overhead not allocated to E&P. Realized and unrealized losses on derivative instruments result from increases in market natural gas prices relating to future periods whereby the swap contracts provided the Company with a fixed price.

Corporate activities reported a loss of \$158.4 million in 2025, an unfavorable variance of \$49.3 million compared to 2024. The unfavorable variance was primarily due to a foreign exchange loss of \$29.4 million in 2025 compared to a foreign exchange gain of \$45.4 million in 2024, as a result of unrealized exchange rate changes relating to our Canadian subsidiary. This increase was partially offset by lower interest charges in 2025 due to no debt repayment fees in the current year, and a higher income tax benefit attributable to our Canadian segment as a result of larger current-period losses before income taxes, primarily as a result of foreign exchange.

Financial Condition

The Company's primary sources of liquidity are cash on hand, net cash provided by continuing operations activities and available borrowing capacity under its Amended RCF, as described below. The Company's liquidity requirements, both in the short-term (2026) and long-term (beyond 2026), consist primarily of capital expenditures, debt maturity, retirement and interest payments, working capital requirements, dividend payments, and, as applicable, share repurchases. The Company may, from time to time, redeem, repurchase or otherwise acquire its outstanding notes through open market purchases, tender offers or pursuant to the terms of such securities. The Company believes that the primary sources of liquidity described above will be adequate to fund its liquidity needs over the next 12 months.

Cash Flows

The following table presents the Company's cash flows for the periods presented.

<i>(Millions of dollars)</i>	2025	2024	2023
Net cash provided by (required by):			
Net cash provided by continuing operations activities	\$ 1,247.8	\$ 1,729.0	\$ 1,748.8
Net cash required by investing activities	(1,028.9)	(908.2)	(998.7)
Net cash required by financing activities	(264.1)	(716.5)	(923.7)
Effect of exchange rate changes on cash and cash equivalents	(1.2)	2.2	(1.2)
Net (decrease) increase in cash and cash equivalents	<u>\$ (46.4)</u>	<u>\$ 106.5</u>	<u>\$ (174.8)</u>

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Cash Provided by Continuing Operations Activities

Net cash provided by continuing operations activities in 2025 was \$481.2 million lower compared to 2024. The decrease was primarily attributable to lower revenue from production (\$325.1 million), timing of non-cash working capital (\$148.9 million) settlements, changes in other operating activities, net (\$68.4 million), primarily due to decreased expenditures for asset retirements, and higher other expenses (\$93.2 million), primarily due to Canadian foreign exchange losses, partially offset by lower lease operating expenses (\$171.7 million) and lower exploration expenses \$21.9 million.

The total reductions of operating cash flows for interest paid (which excludes "Early redemption of debt cost" reported in "Financing Activities") during the two years ended December 31, 2025, and 2024 were \$88.1 million and \$78.8 million, respectively. Cash interest paid in 2025 was primarily due to interest payments on outstanding debt. In 2025, cash interest paid was higher than 2024, primarily due to amounts drawn on the RCF. In 2024, cash interest paid was primarily due to interest payments on outstanding debt and accelerated interest payments due to the early redemption, in part, of the 5.875% senior notes due 2027 (2027 Notes), the 6.375% senior notes due 2028 (2028 Notes), and the 7.05% senior notes due 2029 (2029 Notes) for an aggregate redemption amount of \$650.1 million.

Cash Required by Investing Activities

Net cash required by investing activities in 2025 was \$120.8 million higher compared to 2024. The increase was primarily due to higher property additions (\$120.5 million) and higher acquisition capital (\$21.0 million), partially offset by proceeds from realization of contingent consideration receivable from the 2022 sale of Brunei assets.

A reconciliation of "Property additions and dry hole costs" in the Consolidated Statements of Cash Flows to total capital expenditures for continuing operations follows.

<i>(Millions of dollars)</i>	Year Ended December 31,		
	2025	2024	2023
Property additions and dry hole costs per cash flow statements	\$ 1,020.6	\$ 900.1	\$ 1,066.0
Geophysical and other exploration expenses	65.6	44.8	46.0
Acquisition of oil and natural gas properties per the cash flow statements	29.0	8.1	35.6
Capital expenditure accrual changes and other	102.8	11.8	(9.5)
Total capital expenditures	<u>\$ 1,218.0</u>	<u>\$ 964.8</u>	<u>\$ 1,138.1</u>

Total capital expenditures categorized by E&P and corporate activities are presented below.

<i>(Millions of dollars)</i>	Year Ended December 31,		
	2025	2024	2023
Capital Expenditures			
Exploration and production	\$ 1,196.8	\$ 935.7	\$ 1,114.0
Corporate	21.2	29.1	24.1
Total capital expenditures	<u>1,218.0</u>	<u>964.8</u>	<u>1,138.1</u>
Less: acquisition of oil and natural gas properties	<u>29.0</u>	<u>8.1</u>	<u>35.6</u>
Total capital expenditures excluding acquisition of oil and natural gas properties	<u>1,189.0</u>	<u>956.7</u>	<u>1,102.5</u>
Total capital expenditures excluding acquisition of oil and natural gas properties and noncontrolling interest	<u>\$ 1,157.0</u>	<u>\$ 944.7</u>	<u>\$ 1,032.3</u>

Higher capital expenditures in 2025 compared to 2024 were primarily attributable to the Pioneer FPSO purchase in the Gulf of America, exploratory and development drilling in Vietnam, which included progressing the LDV-A platform jacket installation and pipe-laying campaign, and exploratory drilling in Côte d'Ivoire.

Capital expenditures of \$1,218.0 million in 2025 were primarily related to development drilling (\$551.4 million), field development (\$400.2 million) and exploration (\$221.7 million) activities. Development activities were mainly in the Gulf of America (\$330.8 million), primarily related to the Cascade and Chinook, Mormont,

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Zephyrus, and Other Offshore fields, the Eagle Ford Shale (\$365.4 million), the Tupper Montney and the Kaybob Duvernay (\$133.9 million), and Vietnam (\$98.5 million).

Exploration costs in 2025 were \$221.7 million, primarily attributable to activities in Vietnam for the Lac Da Hong-1X (Pink Camel), Block 15-1/05, and Hai Su Vang-1X and Hai Su Vang-2X (Golden Sea Lion), Block 15-2/17 exploration wells, activities in the Gulf of America related to the Cello #1 (Mississippi Canyon 385) and Banjo #1 (Mississippi Canyon 385) exploration wells, and activities in Côte d'Ivoire related to the Bubale-1X (Block CI-709), Civette-1X (Block CI-502), and Caracal-1X (Block CI-102) exploration wells.

Cash Required by Financing Activities

Net cash required by financing activities in 2025 decreased by \$452.4 million compared to 2024. In 2025, cash used in financing activities was principally for year-to-date cash dividends to shareholders of \$1.30 per share (\$186.2 million), the repurchase of common shares (\$102.6 million), excluding excise tax, distributions to the noncontrolling interest in MP GOM (\$63.8 million), and partially offset by net borrowings on the RCF (\$100.0 million).

Liquidity

At December 31, 2025, the Company had approximately \$1.6 billion of liquidity consisting of \$377.2 million in cash and cash equivalents and \$1,249.6 million available on its previous RCF with a major banking consortium.

The Company's previous \$1.35 billion RCF was set to expire in October 2029, and as of December 31, 2025, the Company had \$100.0 million outstanding borrowings under the RCF and \$0.4 million of outstanding letters of credit, which reduce the borrowing capacity of the RCF. Borrowings under the RCF were subject to certain interest rates. Please refer to [Note F](#) for further details. At December 31, 2025, the interest rate in effect on borrowings under the facility was 6.04%. At December 31, 2025, the Company was in compliance with all covenants related to the RCF. Subsequent to year end, in January, 2026, the Company entered into an Amended RCF, a credit agreement governing a \$2.0 billion senior unsecured guaranteed revolving credit facility, with a maturity date in January 2031, which increased and extended the previous RCF.

Cash and invested cash are maintained in several operating locations outside the U.S. As of December 31, 2025, cash and cash equivalents held outside the U.S. included U.S. dollar equivalents of approximately \$152.5 million (2024: \$95.2 million), the majority of which was held in Canada (\$76.5 million), Brunei (\$23.7 million), Côte d'Ivoire (\$21.6 million), and Vietnam (\$8.5 million). In addition, approximately \$7.8 million and \$7.0 million of cash was held in Mexico and the U.K., respectively. In certain cases, the Company could incur cash taxes or other costs should these cash balances be repatriated to the U.S. in future periods. Canada currently collects a 5% withholding tax on any earnings repatriated to the U.S. See [Note H](#) for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the U.S.

Working Capital

<i>(Millions of dollars)</i>	2025	2024
Working capital		
Total current assets	\$ 816.7	\$ 785.3
Total current liabilities	1,062.7	942.8
Net working capital liability	<u>\$ (246.0)</u>	<u>\$ (157.5)</u>

As of December 31, 2025, net working capital had an unfavorable decrease of \$88.5 million compared to December 31, 2024. The decrease was primarily attributable to higher accounts payable (\$100.0 million), higher operating lease liabilities (\$25.6 million), and a lower cash balance (\$46.4 million), partially offset by higher accounts receivable (\$74.2 million). Higher accounts payable were primarily due to the timing of payments for certain drilling activities and ongoing workover projects. Higher operating lease liabilities were primarily due to the addition of a new drilling rig and support vessels in Vietnam, partially offset by the purchase of the Pioneer FPSO and normal amortization of leases. Higher accounts receivable were due primarily to timing of partner billing and related cash calls, partially offset by lower pricing.

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Capital Employed

A summary of capital employed as of December 31, 2025 and 2024 follows.

<i>(Millions of dollars)</i>	December 31, 2025		December 31, 2024	
	Amount	%	Amount	%
Capital employed				
Long-term debt	\$ 1,382.6	21.3 %	\$ 1,274.5	19.7 %
Murphy shareholders' equity	5,118.4	78.7 %	5,194.3	80.3 %
Total capital employed	<u>\$ 6,501.0</u>	<u>100.0 %</u>	<u>\$ 6,468.8</u>	<u>100.0 %</u>

As of December 31, 2025, long-term debt increased by \$108.1 million compared to December 31, 2024, primarily as a result of amounts drawn on the RCF. As of December 31, 2025, the fixed-rate notes had a weighted average maturity of 8.3 years and a weighted average coupon of 6.1%. Refer to [Note F](#) for additional details.

Murphy's shareholders' equity decreased by \$75.9 million in 2025 primarily due to dividends (\$186.2 million) and shares repurchased (\$100.8 million), including excise tax, partially offset by foreign currency translation (\$74.0 million), net income (\$104.2 million), and awarded restricted stock (\$22.4 million). A summary of transactions in stockholders' equity accounts is presented in the "[Consolidated Statements of Stockholders' Equity](#)" on page [72](#) of this Form 10-K report.

Other Balance Sheet Activity - Long-Term Assets and Liabilities

Other significant changes in Murphy's balance sheet at the end of 2025, compared to 2024 are discussed below.

Property, plant and equipment, net of depreciation, increased \$81.7 million principally due to capital expenditures in the year, partially offset by DD&A expense (\$977.8 million) and foreign exchange rates applicable for the Canadian assets. Capital expenditures are discussed above in the "[Cash Required by Investing Activities](#)" section.

Murphy had commitments for capital expenditures of approximately \$551.2 million at December 31, 2025 (2024: \$417.0 million). This amount primarily related to approved expenditures of \$127.5 million in Vietnam for the Lac Da Vang (Golden Camel) field development project, \$45.0 million for exploration activities in Côte d'Ivoire, \$82.6 million in the Eagle Ford Shale, \$245.3 million relating to Gulf of America interests, primarily related to Cascade and Chinook operated field and exploration activities, as well as \$49.8 million relating to interests in Canada Onshore, primarily at the Kaybob Duvernay.

Operating lease assets increased \$27.9 million principally due to lease additions in Vietnam, partially offset by the depreciation of these assets.

Deferred income tax liabilities increased \$42.5 million due to utilization of our net operating loss, partially offset by other capital-related tax effects.

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Other Key Performance Metrics

The Company uses other operational performance and income metrics to review operational performance. Management uses adjusted net income, earnings before interest, taxes, depreciation and amortization (EBITDA), adjusted EBITDA, earnings before interest, taxes, depreciation and amortization, and exploration expenses (EBITDAX) and adjusted EBITDAX internally to evaluate the Company's operational performance and trends between periods and relative to its industry competitors. Adjusted net income, adjusted EBITDA and adjusted EBITDAX exclude certain items that management believes affect the comparability of results between periods. Management believes this information may be useful to investors and analysts to gain a better understanding of the Company's financial results. Adjusted net income, EBITDA, adjusted EBITDA, EBITDAX and adjusted EBITDAX are non-GAAP financial measures and should not be considered a substitute for net income or cash provided by operating activities as determined in accordance with GAAP.

The following table reconciles net income attributable to Murphy to adjusted net income from continuing operations attributable to Murphy.

	Year Ended December 31,		
	2025	2024	2023
<i>(Millions of dollars, except per share amounts)</i>			
Net income attributable to Murphy (GAAP) ¹	\$ 104.2	\$ 407.2	\$ 661.6
Discontinued operations (income) loss	(0.5)	2.8	1.5
Net income from continuing operations	103.7	410.0	663.1
Adjustments:			
Impairment of assets ¹	92.0	62.9	–
Foreign exchange (gain) loss	29.4	(45.4)	10.9
Unrealized (gain) loss on derivative instruments	(1.7)	1.7	–
Write-off of previously suspended exploration well	–	26.1	17.1
Unrealized loss on contingent consideration	–	–	7.1
Asset retirement obligation losses	–	–	16.9
Refinancing and early redemption of debt costs (non-cash)	–	3.7	–
Total adjustments, before taxes	119.7	49.0	52.0
Income tax (benefit) expense related to adjustments	(26.4)	(8.3)	(6.4)
Tax benefits on investments in foreign areas	–	(34.0)	–
Total adjustments, after taxes	93.3	6.7	45.6
Adjusted net income from continuing operations attributable to Murphy (Non-GAAP)	\$ 197.0	\$ 416.7	\$ 708.7
Net income from continuing operations per average diluted share	\$ 0.72	\$ 2.72	\$ 4.23
Adjusted net income from continuing operations per average diluted share (Non-GAAP)	\$ 1.37	\$ 2.76	\$ 4.52

¹ Excludes amounts attributable to the noncontrolling interest in MP GOM.

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The following table reconciles net income attributable to Murphy to EBITDA, adjusted EBITDA, EBITDAX and adjusted EBITDAX attributable to Murphy.

<i>(Millions of dollars)</i>	Year Ended December 31,		
	2025	2024	2023
Net income attributable to Murphy (GAAP) ¹	\$ 104.2	\$ 407.2	\$ 661.6
Income tax expense	44.6	78.3	195.9
Interest expense, net	96.1	105.9	112.4
Depreciation, depletion and amortization expense ¹	946.8	833.1	836.7
EBITDA attributable to Murphy (Non-GAAP)	\$ 1,191.7	\$ 1,424.5	\$ 1,806.6
Exploration expenses ¹	111.6	133.5	204.6
EBITDAX attributable to Murphy (Non-GAAP)	\$ 1,303.3	\$ 1,558.0	\$ 2,011.2
EBITDA attributable to Murphy (Non-GAAP)	\$ 1,191.7	\$ 1,424.5	\$ 1,806.6
Impairment of asset ¹	92.0	62.9	–
Foreign exchange (gain) loss	29.4	(45.4)	10.8
Accretion of asset retirement obligations ¹	51.5	46.9	41.0
Unrealized (gain) loss on derivative instruments	(1.7)	1.7	–
Write-off of previously suspended exploration well	–	26.1	17.1
Asset retirement obligation losses	–	–	16.9
Unrealized loss on contingent consideration	–	–	7.1
Discontinued operations (income) loss	(0.5)	2.8	1.5
Adjusted EBITDA attributable to Murphy (Non-GAAP)	\$ 1,362.4	\$ 1,519.5	\$ 1,901.0
Other exploration expenses ²	111.6	107.4	187.5
Adjusted EBITDAX attributable to Murphy (Non-GAAP)	\$ 1,474.0	\$ 1,626.9	\$ 2,088.5

¹ Excludes amounts attributable to the noncontrolling interest in MP GOM.

² Other exploration expenses consist of exploration expenses as reported in the Consolidated Statements of Operations excluding amounts relating to the write-off of previously suspended exploration well included in Adjusted EBITDA calculation above.

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

Management uses FCF and adjusted FCF internally as additional measures of liquidity to evaluate the Company's ability to internally generate cash, excluding the timing impacts of working capital, and to measure funds available for investing and financing activities. Management also believes this information may be useful to investors and analysts to monitor the Company's financial health and its performance over time. FCF and adjusted FCF are non-GAAP financial measures and should not be considered a substitute for net cash provided by operating, investing, or financing activities as determined in accordance with GAAP.

The following table reconciles net cash provided by continuing operations activities to FCF and adjusted FCF.

<i>(Millions of dollars)</i>	Year Ended December 31,		
	2025	2024	2023
Net cash provided by continuing operations activities (GAAP)	\$ 1,247.8	\$ 1,729.0	\$ 1,748.8
Exclude: (decrease) increase in non-cash working capital	74.1	(74.9)	99.4
Operating cash flow excluding working capital adjustments	1,321.9	1,654.1	1,848.2
Less: property additions and dry hole costs ¹	(1,020.6)	(900.1)	(1,066.0)
Free cash flow (Non-GAAP)	\$ 301.3	\$ 754.0	\$ 782.2
Less: cash dividends paid	(186.2)	(180.0)	(171.0)
Less: distributions to noncontrolling interest	(63.8)	(118.6)	(29.4)
Less: debt costs	(0.4)	(40.6)	–
Less: contingent consideration payment	–	–	(60.2)
Less: withholding tax on stock-based incentive awards	(9.8)	(25.3)	(14.3)
Less: acquisition of oil and natural gas properties	(29.0)	(8.0)	(35.6)
Adjusted free cash flow (Non-GAAP)	\$ 12.1	\$ 381.5	\$ 471.7

¹ Property additions for the year ended December 31, 2025 include a payment of \$125.0 million for the Pioneer FPSO in the U.S. Offshore, including amounts attributable to the noncontrolling interest in MP GOM.

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

Environmental, Health and Safety Matters

Murphy faces various environmental, health and safety risks that are inherent in exploring for, developing and producing hydrocarbons. To help manage these risks, the Company has established a robust health, safety and environmental governance program comprised of a worldwide policy, guiding principles, annual goals and a management system incorporating oversight at each business unit, senior leadership and board levels. The Company strives to minimize these risks by continually improving its processes through design, operation and implementation of a comprehensive asset integrity plan, auditing and assessments, and through emergency and oil spill response planning to address any credible risks. These plans are presented to, reviewed and approved by a Health, Safety, Environment and Corporate Responsibility Committee consisting of certain members of the Board.

The oil and natural gas industry is subject to numerous international, foreign, national, state, provincial and local environmental, health and safety laws and regulations. Murphy allocates a portion of both its capital expenditures and its general and administrative budget toward compliance with existing and anticipated environmental, health and safety laws and regulations. These requirements affect virtually all operations of the Company and increase Murphy's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities as well as operating costs for ongoing compliance.

The principal environmental, health and safety laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including methane and other GHG emissions; wildlife, habitat and water protection; the placement, operation and decommissioning of production equipment; and the health and safety of our employees, contractors and communities where our operations are located. These laws and regulations also generally require permits for existing operations, as well as the construction or development of new operations and the decommissioning of facilities once production has ceased. Violations can give rise to sanctions including significant civil and criminal penalties, injunctions, construction bans and delays.

Further information on environmental, health and safety laws and regulations applicable to Murphy are contained in the "[Business](#)" section beginning page 9.

Climate Change and Emissions

The world's population and standard of living are growing steadily along with the demand for energy. Murphy recognizes that this may generate increasing amounts of GHG, which could raise important climate change concerns. Murphy works to assess the Company's governance, strategy, risk identification, and management and measurement of climate risks and opportunities in order to remain in alignment with the TCFD framework. While oversight of the TCFD framework has undergone changes, including relating to the role of the International Financial Reporting Standards Foundation in overseeing the framework, the TCFD framework continues to inform climate-related reporting practices. Murphy's disclosures related to its alignment with the TCFD framework are included in the Company's 2025 Sustainability Report issued on August 6, 2025, which is not incorporated by reference hereto.

Other Matters

Impact of inflation - In 2025, inflation in the U.S. and in other countries where the Company operates began to moderate relative to the sustained higher inflation seen since 2021. However, U.S. and global trade policy is continually developing, and it is unclear whether this trend will continue or reverse as we enter 2026 and beyond. The Company's revenues, capital and operating costs are influenced to a larger extent by specific price changes in the oil and natural gas industry and allied industries rather than by changes in general inflation. Crude oil prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC+ members' production levels and/or attitudes of traders concerning supply and demand in the future. Costs for oil field goods and services are usually affected by the worldwide prices for crude oil.

To combat impacts of inflation and/or supply and demand factors, Murphy has dedicated personnel in marketing and procurement departments, focused on managing supply chain and input costs. Murphy also has certain transportation, processing and production handling services costs fixed through long-term contracts and

PART II

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

commitments and therefore is partially protected from potential increases in the price of services. However, from time to time, Murphy will seek to enter new commitments, exercise options to extend contracts and retender contracts for rigs and other industry services which could expose Murphy to the impact of higher costs. Murphy continues to strive toward safely executing our work in an ever-increasingly efficient manner to mitigate potential inflationary pressures in its business.

Natural gas prices are also affected by supply and demand factors, which are often influenced by the weather and by the fact that delivery of natural gas can be restricted to specific geographic areas. Natural gas prices can also be impacted by the demand for lower-carbon energy sources.

As a result of the overall volatility of oil and natural gas prices, it is not possible to predict the Company's future cost of oil field goods and services.

Critical Accounting Estimates - In preparing the Company's consolidated financial statements in accordance with GAAP, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company's accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

Oil and natural gas proved reserves - Oil and natural gas proved reserves are defined by the SEC as those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire (unless evidence indicates that renewal is reasonably certain). Proved developed reserves of oil and natural gas 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, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use an unweighted average of the oil and natural gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas prices and reserve assumptions when making its own internal economic property evaluations. Changes in oil and natural gas prices can lead to a decision to start up or shut in production, which can lead to revisions to reserves quantities.

Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Reserves revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligation (ARO) liabilities. Downward reserves revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and natural gas reserves revisions that will be required in future periods.

The Company's proved reserves of oil and natural gas are presented on pages [111](#) to [120](#) of this Form 10-K report. Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data (including hydrocarbon prices, operating costs, and development costs), and commercially available technologies, to establish "reasonable certainty" of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analog-based studies.

Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field-tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of

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

and confidence in Murphy's proved reserves estimates. It was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

See further discussion of proved reserves and changes in proved reserves during the three years ended December 31, 2025 beginning on pages [4](#) and [111](#) of this Form 10-K report.

Property, Plant and Equipment - impairment of long-lived assets – The Company continually monitors its long-lived assets recorded in "Property, plant and equipment" in the Consolidated Balance Sheets to ensure that they are fairly presented. The Company must evaluate its property, plant and equipment for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from undiscounted future net cash flows.

A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital, operating and abandonment costs and future inflation levels.

The need to test a long-lived asset for impairment can be based on several factors, including, but not limited to, a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, or other changes to contracts, environmental, health and safety laws and regulations, tax laws or other regulatory changes. All of these factors must be considered when evaluating a property's carrying value for possible impairment.

Due to the volatility of world oil and natural gas markets, the actual sales prices for oil and natural gas have often been different from the Company's projections.

Estimates of future oil and natural gas production and sales volumes are based on a combination of proved and risked probable reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available.

The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated.

In 2025, the Company recognized a pretax non-cash impairment charge of \$115.0 million (\$92.0 million excluding NCI) to reduce the carrying value at the Dalmatian field, in the Gulf of America, as certain projects in the field were less competitive for capital allocation.

In 2024, the Company recognized pretax non-cash impairment charges of \$62.9 million to reduce the carrying values at select properties. The Company recognized impairments of \$34.5 million, related to the Calliope field, and \$28.4 million, related to the Nearly Headless Nick field, both in the Gulf of America. Both impairment charges were due to subsurface issues that led to reserve reductions.

See also [Note D](#) for further discussion of impairment charges.

Income taxes – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company; and (d) changes to regulations may be subject to different interpretations and require future clarification from issuing authorities or others.

The Company has deferred tax assets mostly relating to U.S. net operating losses, liabilities for dismantlement, retirement benefit plan obligations and net deferred tax liabilities relating to tax and accounting basis differences for property, plant and equipment.

PART II

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

The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization and reduces such assets to the expected realizable amount by a valuation allowance if 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 valuation allowances, we consider all available positive and negative evidence. Positive evidence includes projected future taxable income and assessment of future business assumptions, a history of utilizing tax assets before expiration, significant proven and probable reserves and reversals of taxable temporary differences. Negative evidence includes losses in recent years.

As of December 31, 2025 the Company had a U.S. deferred tax asset associated with net operating losses of \$225.0 million. In reviewing the likelihood of realizing this asset, the Company considered the reversal of taxable temporary differences, carryforward periods and future taxable income estimates based on projected financial information which, based on currently available evidence, we believe to be reasonably likely to occur. Certain estimates and assumptions are used in the estimation of future taxable income, including (but not limited to) (a) future commodity prices for oil and natural gas, (b) estimated reserves for oil and natural gas, (c) expected timing of production, (d) estimated lease operating costs and (e) future capital requirements. In the future, the underlying actual assumptions utilized in estimating future taxable income could be different and result in different conclusions about the likelihood of the future utilization of our net operating loss carryforwards.

Accounting for retirement and postretirement benefit plans – Murphy and certain of its subsidiaries maintain defined benefit retirement plans covering certain full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is estimated by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate, which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Based on bond yields as of December 31, 2025, the Company has used a weighted average discount rate of 5.40% at year end 2025 for the primary U.S. plans. This weighted average discount rate is 0.2% lower than prior year, which increased the Company's recorded liabilities for retirement plans compared to a year ago. The Company assumed a return on plan assets of 7.70% for the primary U.S. plan and periodically reconsiders the appropriateness of this and other key assumptions. The Company's retirement and postretirement plan (health care and life insurance benefit plans) expenses in 2026 are expected to be \$0.4 million lower than in 2025 primarily due to higher actual return on plan assets, partially offset by an increase in the benefit obligations at December 31, 2025 compared to the prior year.

In 2025, the Company paid \$25.1 million into various retirement plans and \$12.9 million into postretirement plans. In 2026, the Company is expecting to fund payments of approximately \$24.5 million into various retirement plans and \$4.7 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected.

Recent Accounting Pronouncements

See [Note B](#) in our Consolidated Financial Statements regarding the impact or potential impact of recent accounting pronouncements upon our financial position and results of operations.

PART II

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

Contractual obligations and guarantees – The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure plans and other long-term liabilities. Total payments due after 2025 under such contractual obligations and arrangements are shown in the table below. Amounts are undiscounted and therefore may differ to those presented in the financial statements.

<i>(Millions of dollars)</i>	Amount of Obligations				
	Total	2026	2027 - 2028	2029 - 2030	After 2030
Debt, excluding finance leases and interest	\$ 1,384.8	\$ –	\$ 227.5	\$ 217.5	\$ 939.8
Operating and finance leases	1,024.8	318.9	215.8	123.0	367.1
Capital expenditures, drilling rigs and other ¹	1,648.0	761.1	252.0	160.2	474.7
Other long-term liabilities, including debt interest ²	2,344.6	129.6	230.6	450.2	1,534.2
Total	<u>\$ 6,402.2</u>	<u>\$ 1,209.6</u>	<u>\$ 925.9</u>	<u>\$ 950.9</u>	<u>\$ 3,315.8</u>

¹ Capital expenditures, drilling rigs and other includes \$28.1 million, \$25.4 million, \$7.7 million, \$1.0 million and \$0.6 million in 2026 for approved capital projects in non-operated interests in the Gulf of America, the Eagle Ford Shale, Canada Offshore, Brunei, and Canada Onshore, respectively.

Also includes \$72.2 million (2026), \$141.1 million (2027 - 2028), \$81.0 million (2029 - 2030) and \$235.9 million (After 2030) for pipeline transportation commitments in Canada.

Also includes \$3.7 million (2026), \$7.5 million (2027 - 2028), \$7.4 million (2029 - 2030) and \$14.3 million (After 2030) for long-term take-or-pay commitments relating to natural gas processing in Canada.

Also includes \$23.6 million (2026), \$47.1 million (2027 - 2028), \$48.1 million (2029 - 2030) and \$176.8 million (After 2030) for the purpose of supporting future production activities in Vietnam.

² Other long-term liabilities includes debt interest and future cash outflows for ARO liabilities.

The Company has entered into agreements to lease production facilities for various producing oil fields as well as other arrangements that require future payments as described in the following section. The Company's share of the contractual obligations under these leases and other arrangements has been included in the table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. Total outstanding letters of credit were \$211.8 million as of December 31, 2025.

Subsequent to the balance sheet date, the Company completed a series of transactions regarding its long-term debt arrangements and RCF. In January 2026, the Company closed a public offering of \$500.0 million aggregate principal amount of its 6.500% senior notes due 2034 (2034 Notes), used the proceeds to redeem an aggregate \$227.5 million of its outstanding 2027 Notes and 2028 Notes, repaid \$100.0 million that was outstanding on the previous RCF, as of December 31, 2025, and expects to use the remaining proceeds to cover transaction-related fees and expenses and for general corporate purposes. See [Note F](#) for additional information.

Material off-balance sheet arrangements – Certain U.S. transportation contracts require minimum monthly payments through 2045, while Canada Onshore transportation and processing contracts call for minimum monthly payments through 2051. Future required minimum annual payments under these arrangements are included in the contractual obligation table above.

PART II

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

Outlook

The oil and natural gas industry is impacted by global commodity pricing. As a result, the prices for the Company's primary products are often volatile and are affected by the levels of supply and demand for energy. As discussed in the "[Results of Operations](#)" section on revenues, on page [38](#), lower average crude oil price during 2025 directly impacted the Company's product sales revenue.

As of close on February 23, 2026, forward price curves for existing forward contracts for the remainder of 2026 and 2027 are shown in the table below.

	2026	2027
NYMEX WTI (\$/BBL)	\$ 64.90	\$ 62.02
NYMEX Henry Hub (\$/MMBTU)	3.39	3.72
AECO (US\$ Equivalent/MCF)	1.36	1.90

In 2025, liquids from continuing operations represented approximately 55% of total hydrocarbons produced on a barrels of oil equivalent basis. In 2026, the Company's ratio of hydrocarbon production represented by liquids is expected to be 56%. If the prices for crude oil and natural gas are lower in 2026 or beyond, this will have an unfavorable impact on the Company's operating profits; likewise, if prices are higher, this will have a favorable impact. The Company, from time to time, may choose to use a variety of commodity hedge instruments to reduce commodity price risk, including forward sale fixed financial swaps and long-term fixed-price physical commodity sales.

The Company currently expects average daily production in 2026 to be between 173,000 and 181,000 BOEPD (including a noncontrolling interest of 6,000 BOEPD). If significant price declines occur, the Company will review the option of production curtailments to avoid incurring losses on certain produced barrels.

The oil and natural gas industry and the Company continue to observe higher costs for goods and services used in E&P operations. Murphy continues to manage input costs through its dedicated procurement department focused on managing supply chain and other costs to deliver cash flow from operations.

We cannot predict what impact economic factors (including, but not limited to, inflation, evolving trade policy, global conflicts and possible economic recession) may have on future commodity pricing. Lower prices, should they occur, will result in lower profits and operating cash flows.

The Company's capital expenditure spend for 2026 is expected to be between \$1,200 million and \$1,300 million, excluding NCI. Capital and other expenditures are routinely reviewed and planned capital expenditures may be adjusted to reflect differences between budgeted and forecast cash flow during the year. Capital expenditures may also be affected by asset purchases or sales, which often are not anticipated at the time a budget is prepared. The Company will primarily fund its capital program in 2026 using operating cash flow and available cash. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that capital spending reductions are required and/or borrowings under available credit facilities might be required during the year to maintain funding of the Company's ongoing development projects.

The Company plans to utilize surplus cash (not planned to be used by operations, investing activities, dividends or payment to noncontrolling interests), in accordance with the Company's capital allocation plan designed to allow for additional shareholder returns and debt reduction. Details of the plan can be found in the "Capital Allocation Framework" section of the Company's [Form 8-K](#) filed on August 4, 2022 and [Form 8-K](#) filed on August 8, 2024. The Board has authorized a share repurchase program whereby the Company can repurchase up to \$1,100 million of the Company's common stock. As of December 31, 2025, the Company had \$550.1 million of its common stock remaining available to repurchase under the program.

Subsequent to the balance sheet date, the Company completed a series of transactions regarding its long-term debt arrangements and RCF. In January 2026, the Company closed a public offering of \$500.0 million aggregate principal amount of its 2034 Notes, used the proceeds to redeem an aggregate \$227.5 million of its outstanding 2027 Notes and 2028 Notes, repaid \$100.0 million that was outstanding on the previous RCF, as of December 31, 2025, and expects to use the remaining proceeds to cover transaction-related fees and expenses and for general corporate purposes. In addition, the Company entered into an amendment to its credit agreement which increased its RCF capacity from \$1.35 billion to \$2.0 billion and extended the term of the agreement to 2031. See [Note F](#) for additional information on these transactions.

PART II

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

On January 28, 2026, the Board of Directors declared a quarterly cash dividend on the Common Stock of Murphy Oil Corporation of \$0.35 per share, which on an annualized basis would be \$1.40 per share. The dividend is payable on March 2, 2026, to stockholders of record as of February 17, 2026.

The Company continues to monitor the impact of commodity prices on its financial position and is currently in compliance with the covenants related to the RCF (see [Note F](#)).

As of February 23, 2026, the Company has entered into forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices, as follows.

Area	Commodity	Type	Volumes (MMCF/D)	Price/MCF	Remaining Period	
					Start Date	End Date
Canada	Natural Gas	Fixed price forward sales	50	C\$3.03	1/1/2026	3/31/2026
Canada	Natural Gas	Fixed price forward sales	78	C\$2.94	4/1/2026	6/30/2026
Canada	Natural Gas	Fixed price forward sales	78	C\$2.94	7/1/2026	9/30/2026
Canada	Natural Gas	Fixed price forward sales	59	C\$3.00	10/1/2026	12/31/2026
Canada	Natural Gas	Fixed price forward sales	9.5	C\$3.14	1/1/2027	12/31/2027

PART II

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

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are generally identified through the inclusion of words such as "aim", "anticipate", "believe", "drive", "estimate", "expect", "forecast", "future", "goal", "guidance", "intend", "may", "objective", "outlook", "plan", "position", "potential", "project", "seek", "should", "strategy", "target", "will" or variations of such words and other similar expressions. These statements, which express management's current views concerning future events, results and plans, are subject to inherent risks, uncertainties and assumptions (many of which are beyond our control) and are not guarantees of performance. In particular, statements, express or implied, concerning the Company's future operating results or activities and returns or the Company's ability and intent to replace or increase reserves, increase production, generate returns and rates of return, replace or increase drilling locations, reduce or otherwise control operating costs and expenditures, generate cash flows, pay down or refinance indebtedness, achieve, reach or otherwise meet initiatives, plans, goals, ambitions or targets with respect to emissions, safety matters or other environmental, social and governance matters, make capital expenditures, pay and/or increase dividends or make share repurchases and other capital allocation decisions are forward-looking statements. Factors that could cause one or more of these future events, results or plans not to occur as implied by any forward-looking statement, which consequently could cause actual results or activities to differ materially from the expectations expressed or implied by such forward-looking statements, include, but are not limited to: macro conditions in the oil and natural gas industry, including supply and demand levels, actions taken by major oil exporters and the resulting impacts on commodity prices; geopolitical concerns; increased volatility or deterioration in the success rate of our exploration programs or in our ability to maintain production rates and replace reserves; reduced customer demand for our products due to environmental, regulatory, technological or other reasons; adverse foreign exchange movements; political and regulatory instability in the markets where we do business; the impact on our operations or markets of health pandemics and related government responses; natural hazards impacting our operations or markets; any other deterioration in our business, markets or prospects; cyber attacks and other cybersecurity risks; any failure to obtain necessary regulatory approvals; the impact of current and future laws, rulings and governmental regulations; any inability to service or refinance our outstanding debt or to access debt markets at acceptable prices; or adverse developments in the U.S. or global capital markets, credit markets, banking system or economies in general, including inflation, trade policies, tariffs and other trade restrictions. For further discussion of factors that could cause one or more of these future events or results not to occur as implied by any forward-looking statement, see "[Item 1A. Risk Factors](#)", which begins on page [13](#) of this Annual Report on Form 10-K. Investors and others should note that we may announce material information using SEC filings, press releases, public conference calls, webcasts and the investors page of our website. We may use these channels to distribute material information about the Company; therefore, we encourage investors, the media, business partners and others interested in the Company to review the information we post on our website. The information on our website is not part of, and is not incorporated into, this report. Each forward-looking statement contained in this report speaks only as of the date of this report. Except as required by applicable law, Murphy Oil Corporation undertakes no duty to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise.

PART II

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with prices of crude oil, natural gas and petroleum products, foreign currency exchange rates and interest rates. As described in [Note K](#), Murphy periodically makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

Commodity Price Risk

There were no commodity transactions in place as of December 31, 2025, covering certain future U.S. oil and natural gas sales.

Foreign Exchange Risk

There were no derivative foreign exchange contracts in place as of December 31, 2025.

Interest Rate Risk

At December 31, 2025, long-term debt was \$1,382.6 million. The fixed-rate notes have a weighted average coupon of 6.1%. The Company's previous and Amended RCF agreements provide for variable interest rate borrowings. As of December 31, 2025, we had \$100.0 million outstanding under the previous RCF, and a 10% increase in the average interest rate would have increased our quarterly interest expense by approximately \$0.3 million. Actual results may vary due to changes in the amount of variable rate debt outstanding.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages [68](#) through [127](#) of this Form 10-K report.

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

None.

Item 9A. CONTROLS AND PROCEDURES

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by the Company to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, with the participation of the Company's management, as of December 31, 2025, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2025. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2025 and their report is included on page [67](#) of this Form 10-K report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2025 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

Item 9B. OTHER INFORMATION

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

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page [29](#) of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2026 under the captions "Election of Directors" and "The Board and Committees."

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance tab at ir.murphyoilcorp.com. Stockholders may also obtain, free of charge, a copy of the Code of Ethical Conduct for Executive Management by writing to the Corporate Secretary at 9805 Katy Freeway, Suite G-200, Houston, TX 77024. Any future amendments to or waivers of the Code of Ethical Conduct for Executive Management will be posted on the Company's Website.

Murphy Oil has also adopted an insider trading policy governing the purchase, sale, and/or other dispositions of our securities by our directors, officers, employees and contractors and consultants who have access to material nonpublic information, as well as the Company itself, that we believe is reasonably designed to promote compliance with insider trading laws, rules and regulations, and the exchange listing standards applicable to us. A copy of our insider trading policy, including any amendments thereto, is filed as [Exhibit 19.1](#) to this Form 10-K.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2026 under the captions "Compensation Discussion and Analysis" and "How We Are Compensated" and in various compensation schedules.

As required by U.S. federal securities laws, the Company implemented its incentive-based compensation recoupment (clawback) policy providing for the recovery of erroneously awarded incentive-based compensation received by current or former executive officers. We have filed our written recoupment policy as [Exhibit 97.1](#) to this Form 10-K report and as of December 31, 2025, there have been no accounting restatements requiring compensation recoupment.

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

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2026 under the caption "Our Stockholders" and in the "Equity Compensation Plan Information".

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2026 under the caption "Election of Directors".

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is KPMG LLP, Houston, TX, Auditor Firm ID: 185.

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 13, 2026 under the caption "Audit Committee Report".

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

- (a) **1. Financial Statements** – The consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are located or begin on the pages of this Form 10-K report as indicated below.

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PART IV

2. **Financial Statement Schedules** – All financial statement schedules are omitted because either they are not applicable, or the required information is included in the consolidated financial statements or notes thereto.
3. **Exhibits** – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are considered furnished rather than filed as indicated by double asterisks (**), or that are incorporated by reference. Exhibits other than those listed have been omitted since they either are not required or are not applicable.

Exhibit No.		Incorporated by Reference to the Indicated Filing by Murphy Oil Corporation
2.1	<u>Purchase and sale agreement dated as of April 19, 2019 between LLOG Bluewater Holdings, LLC and LLOG Exploration Offshore, LLC, as seller, and Murphy Exploration & Production Company - USA, as purchaser.</u>	Exhibit 2.1 to Form 8-K filed June 5, 2019
2.2	<u>First Amendment to Purchase and Sale Agreement dated as of May 31, 2019 among Murphy Exploration & Production Company - USA, LLOG Exploration Offshore, L.L.C. and LLOG Bluewater Holdings, L.L.C.</u>	Exhibit 2.2 to Form 8-K filed June 5, 2019
2.3	<u>Contribution Agreement dated as of October 10, 2018 among Murphy Exploration & Production Company - USA, Petrobras America Inc. and MP Gulf of Mexico, LLC</u>	Exhibit 2.1 to Form 10-K filed February 27, 2019
3.1	<u>Certificate of Incorporation of Murphy Oil Corporation, as amended effective May 11, 2005</u>	Exhibit 3.1 to Form 10-K filed February 28, 2011
3.2	<u>By-Laws of Murphy Oil Corporation, as amended effective August 5, 2020</u>	Exhibit 3.2 to Form 10-Q filed August 6, 2020
4.1	<u>Supplemental Indenture dated as of May 4, 1999 between Murphy Oil Corporation and SunTrust Bank, Nashville, N.A., as trustee, relating to 7.05% Notes due 2029</u>	Exhibit 4.2 to Form 10-K filed March 16, 2005
4.2	<u>Indenture dated as of May 18, 2012 between Murphy Oil Corporation and U.S. Bank National Association, as trustee</u>	Exhibit 4.1 to Form 8-K filed May 18, 2012
4.3	<u>Second Supplemental Indenture dated as of November 30, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.125% Notes due 2042</u>	Exhibit 4.1 to Form 8-K filed November 30, 2012
4.4	<u>Fifth Supplemental Indenture dated as of November 27, 2019, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, and Wells Fargo Bank, National Association, as series trustee, relating to 5.875% Notes due 2027</u>	Exhibit 4.2 to Form 8-K filed November 27, 2019
4.5	<u>Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934</u>	Exhibit 4.9 to Form 10-K filed February 27, 2020
4.6	<u>Sixth Supplemental Indenture dated as of March 5, 2021, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, and Wells Fargo Bank, National Association as series trustee, relating to 6.375% Notes due 2028</u>	Exhibit 4.2 to Form 8-K filed March 5, 2021
4.7	<u>Seventh Supplemental Indenture dated as of October 3, 2024, between Murphy Oil Corporation and Regions Bank, as trustee, relating to 6.000% Notes due 2032</u>	Exhibit 4.2 to Form 8-K filed October 3, 2024
4.8	<u>Eighth Supplemental Indenture, dated as of January 23, 2026, between Murphy Oil Corporation and Regions Bank, as trustee (including the Form of 6.500% Notes due 2034)</u>	Exhibit 4.2 to Form 8-K filed January 23, 2026
10.1	<u>Murphy Oil Corporation Annual Incentive Plan</u>	Exhibit 10.3 to Form 10-K filed February 25, 2022
10.2	<u>Murphy Oil Corporation 2020 Long-Term Incentive Plan</u>	Exhibit A to definitive proxy statement filed March 30, 2020

PART IV

10.3	<u>Form of employee performance-based restricted stock unit – stock settled grant agreement (2020 LTI Plan)</u>	Exhibit 10.21 to Form 10-K filed February 26, 2021
10.4	<u>Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2020 LTI Plan)</u>	Exhibit 10.22 to Form 10-K filed February 26, 2021
10.5	<u>Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2020 LTI Plan)</u>	Exhibit 10.23 to Form 10-K filed February 26, 2021
10.6	<u>Form of employee time-based restricted stock unit – cash settled 3-year grant agreement (2020 LTI Plan)</u>	Exhibit 10.24 to Form 10-K filed February 26, 2021
10.7	<u>Form of employee time-based restricted stock unit – cash settled 5-year grant agreement (2020 LTI Plan)</u>	Exhibit 10.25 to Form 10-K filed February 26, 2021
10.8	<u>Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors</u>	Exhibit A to definitive proxy statement filed March 23, 2018
10.9	<u>First Amendment to the 2018 Stock Plan for Non-Employee Directors</u>	Exhibit 10.1 to Form 8-K filed April 25, 2018
10.10	<u>Second Amendment to the 2018 Stock Plan for Non-Employee Directors</u>	Exhibit 10.24 to Form 10-K filed February 27, 2020
10.11	<u>Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)</u>	Exhibit 10.20 to Form 10-K filed February 27, 2019
10.12	<u>Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)</u>	Exhibit 10.26 to Form 10-K filed February 27, 2020
10.13	<u>Murphy Oil Corporation 2021 Stock Plan for Non-Employee Directors</u>	Exhibit A to definitive proxy statement filed March 26, 2021
10.14	<u>Form of non-employee director restricted stock unit award – stock settled grant agreement (2021 NED Plan)</u>	Exhibit 10.27 to Form 10-Q filed August 5, 2021
10.15	<u>Murphy Oil Corporation Non-Qualified Deferred Compensation Plan for Non-Employee Directors</u>	Exhibit 10.6 to Form 10-K filed February 26, 2016
10.16	<u>Trademark License Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.</u>	Exhibit 10.4 to Form 8-K filed September 5, 2013
10.17	<u>Form of employee performance-based restricted stock unit (2020 LTI Plan)</u>	Exhibit 10.23 to Form 10-Q filed May 7, 2025
10.18	<u>Form of employee time-based restricted stock unit – A (2020 LTI Plan)</u>	Exhibit 10.24 to Form 10-Q filed May 7, 2025
10.19	<u>Form of employee time-based restricted stock unit – B (2020 LTI Plan)</u>	Exhibit 10.25 to Form 10-Q filed May 7, 2025
10.20	<u>Form of employee time-based restricted stock unit – C (2020 LTI Plan)</u>	Exhibit 10.33 to Form 10-K filed February 23, 2024
10.21	<u>Form of employee time-based restricted stock unit – D (2020 LTI Plan)</u>	Exhibit 10.34 to Form 10-K filed February 23, 2024
10.22	<u>Form of non-employee director elective restricted stock unit (2021 NED Plan)</u>	Exhibit 10.35 to Form 10-Q filed May 2, 2024
10.23	<u>Severance Protection Agreement dated as of August 7, 2013 between Murphy Oil Corporation and Roger W. Jenkins</u>	Exhibit 10.1 to Form 8-K filed August 9, 2013
10.24	<u>Amendment to Severance Protection Agreement dated as of August 7, 2013, between Murphy Oil Corporation and Roger W. Jenkins</u>	Exhibit 10.1 to Form 10-Q filed May 2, 2019
10.25	<u>Credit Agreement, dated as of October 7, 2024, among Murphy Oil Corporation, Murphy Exploration & Production Company – International and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank N.A., as administrative agent, and the lenders party thereto</u>	Exhibit 10.1 to Form 8-K filed October 7, 2024
10.26	<u>Form of Severance Protection Agreement</u>	Exhibit 10.32 to Form 10-K filed February 27, 2025

PART IV

10.27	<u>First Amendment to the New Credit Agreement dated as of February 6, 2025 among Murphy Oil Corporation, Murphy Exploration & Production Company - International and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party hereto</u>	Exhibit 10.33 to Form 10-K filed February 27, 2025
10.28	<u>Murphy Oil Corporation 2025 Long-Term Incentive Plan</u>	Exhibit A to definitive proxy statement filed on March 28, 2025
10.29	<u>Form of employee performance-based restricted stock unit (2025 LTI Plan)</u>	Exhibit 10.35 to Form 10-Q filed November 5, 2025
10.30	<u>Form of employee time-based restricted stock unit - A (2025 LTI Plan)</u>	Exhibit 10.36 to Form 10-Q filed November 5, 2025
10.31	<u>Second Amendment to the Credit Agreement dated as of January 2, 2026 among Murphy Oil Corporation, Murphy Exploration & Production Company - International and Murphy Oil Company Ltd. as borrowers, Murphy Exploration & Production Company and Murphy Exploration & Production Company - USA, as guarantors, JP Morgan Chase Bank, N.A. as administrative agent, and each of the lenders party thereto</u>	Exhibit 10.1 to Form 8-K filed January 6, 2026
*10.32	<u>Form of employee performance-based restricted stock unit – B (2025 LTI Plan)</u>	
*10.33	<u>Form of employee time-based restricted stock unit – B (2025 LTI Plan)</u>	
*10.34	<u>Form of employee time-based restricted stock unit – C (2025 LTI Plan)</u>	
*10.35	<u>Form of employee time-based restricted stock unit – D (2025 LTI Plan)</u>	
19.1	<u>Murphy Oil Corporation Insider Trading Policy</u>	Exhibit 19.1 to Form 10-K filed February 27, 2025
*21.1	<u>Subsidiaries of Murphy Oil Corporation</u>	
*23.1	<u>Consent of Independent Registered Public Accounting Firm</u>	
*23.2	<u>Consent of Ryder Scott Company, L.P.</u>	
*23.3	<u>Consent of McDaniel & Associates Consultants Ltd.</u>	
*23.4	<u>Consent of Netherland, Sewell & Associates, Inc.</u>	
*23.5	<u>Consent of GLJ Petroleum Consultants Ltd.</u>	
*31.1	<u>Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</u>	
*31.2	<u>Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002</u>	
**32.1	<u>Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002</u>	
97.1	<u>Murphy Oil Corporation Compensation Recoupment Policy</u>	Exhibit 10.29 to Form 10-K filed February 23, 2024
*99.1	<u>Ryder Scott independent reserves audit report for MP GOM JV</u>	
*99.2	<u>Ryder Scott independent reserves audit report for U.S. Onshore</u>	
*99.3	<u>McDaniel independent reserves audit report for Canada Onshore</u>	
*99.4	<u>Netherland, Sewell & Associates, Inc. independent reserves audit report U.S. Gulf of America</u>	
*99.5	<u>GLJ independent reserves audit for Canada Offshore</u>	
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document	
101.SCH	Inline XBRL Taxonomy Extension Schema Document	
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document	
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase	
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)	

PART IV

Item 16. FORM 10-K SUMMARY

None.

PART IV

SIGNATURES

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

MURPHY OIL CORPORATION

By /s/ ERIC M. HAMBLY Date: February 25, 2026
Eric M. Hambly, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 25, 2026 by the following persons on behalf of the registrant and in the capacities indicated.

 /s/ CLAIBORNE P. DEMING
Claiborne P. Deming, Chairman and Director

 /s/ JEFFREY W. NOLAN
Jeffrey W. Nolan, Director

 /s/ ERIC M. HAMBLY
Eric M. Hambly, President and
Chief Executive Officer and Director
(Principal Executive Officer)

 /s/ ROBERT N. RYAN, JR.
Robert N. Ryan, Jr., Director

 /s/ LAWRENCE R. DICKERSON
Lawrence R. Dickerson, Director

 /s/ LAURA A. SUGG
Laura A. Sugg, Director

 /s/ MICHELLE A. EARLEY
Michelle A. Earley, Director

 /s/ ROBERT B. TUDOR, III
Robert B. Tudor, III, Director

 /s/ ELISABETH W. KELLER
Elisabeth W. Keller, Director

 /s/ THOMAS J. MIRELES
Thomas J. Mireles, Executive Vice President
and Chief Financial Officer
(Principal Financial Officer)

 /s/ R. MADISON MURPHY
R. Madison Murphy, Director

 /s/ PAUL D. VAUGHAN
Paul D. Vaughan
Vice President and Controller
(Principal Accounting Officer)

REPORT OF MANAGEMENT - CONSOLIDATED FINANCIAL STATEMENTS

The management of Murphy Oil Corporation is responsible for the preparation and integrity of the accompanying consolidated financial statements and other financial data. The financial statements were prepared in conformity with U.S. generally accepted accounting principles (GAAP) appropriate in the circumstances and include some amounts based on informed estimates and judgments, with consideration given to materiality.

An independent registered public accounting firm, KPMG LLP, has audited the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (PCAOB) and provides an objective, independent opinion about the Company's consolidated financial statements. The Audit Committee of the Board of Directors appoints the independent registered public accounting firm; ratification of the appointment is solicited annually from the shareholders. KPMG LLP's opinion covering the Company's consolidated financial statements can be found on page [65](#).

The Board of Directors appoints an Audit Committee annually to implement and to support the Board's oversight function of the Company's financial reporting, accounting policies, internal controls and independent registered public accounting firm. This Committee is composed solely of directors who are not employees of the Company. The Committee meets routinely with representatives of management, the Company's audit staff and the independent registered public accounting firm to review and discuss the adequacy and effectiveness of the Company's internal controls, the quality and clarity of its financial reporting, the scope and results of independent and internal audits, and to fulfill other responsibilities included in the Committee's Charter. The independent registered public accounting firm and the Company's audit staff have unrestricted access to the Committee, without management presence, to discuss audit findings and other financial matters.

REPORT OF MANAGEMENT - INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). The Company's internal controls have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements in accordance with U.S. GAAP. All internal control systems have inherent limitations, and therefore, can provide only reasonable assurance with respect to the reliability of financial reporting and preparation of consolidated financial statements.

Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2025.

KPMG LLP has performed an audit of the Company's internal control over financial reporting, and their opinion thereon can be found on page [67](#).

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors

Murphy Oil Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries (the Company) as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2025, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 25, 2026 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matter

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

Estimated oil and gas reserves used in the depletion of producing oil and gas properties

As discussed in Note A to the consolidated financial statements, the Company calculates depletion expense related to producing oil and gas properties using the units-of-production method. Under this method, costs to acquire interests in oil and gas properties and costs for the drilling and completion efforts for exploratory wells that find proved reserves and for development wells are capitalized. Capitalized costs of producing oil and gas properties, along with equipment and facilities that support production, are amortized to expense by the units-of-production method. The Company's internal petroleum reserve engineers estimate proved oil and gas reserves and the Company engages third-party petroleum reserve specialists to perform an

independent assessment. For the year ended December 31, 2025, the Company recorded depreciation, depletion, and amortization expense of \$977.8 million.

We identified the assessment of the estimated oil and gas reserves used in the depletion of producing oil and gas properties as a critical audit matter. Complex auditor judgment was required in evaluating the Company's estimate of total proved oil and gas reserves, which is an input to the depletion expense calculation. Estimating proved oil and gas reserves requires the expertise of professional petroleum reserve engineers based on their estimates of forecasted production, forecasted operating costs, future development costs, and oil and gas prices.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's depletion calculation process, including controls related to the estimation of proved oil and gas reserves. We evaluated (1) the professional qualifications of the internal petroleum reserve engineers, third-party petroleum reserve specialists, and external engineering firm, (2) the knowledge, skills, ability of the Company's internal petroleum reserve engineers and third-party petroleum reserve specialists, and (3) the relationship of the third-party petroleum reserve specialists and external engineering firm to the Company. We analyzed and assessed the calculation of depletion expense for compliance with industry and regulatory standards. We compared the forecasted production assumptions used by the Company to historical production rates. We compared the forecasted operating costs to historical results. We also evaluated the forecasted nature and timing of future development costs by obtaining an understanding of the development projects. We assessed the oil and gas prices utilized by the internal petroleum reserve engineers by comparing them to publicly available prices. In addition, we read and considered the report of the Company's third-party petroleum reserve specialists in connection with our evaluation of the Company's proved oil and gas reserve estimates.

/s/ KPMG LLP

We have served as the Company's auditor since 1952.

Houston, Texas

February 25, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors

Murphy Oil Corporation:

Opinion on Internal Control Over Financial Reporting

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2025 and 2024, the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2025, and the related notes (collectively, the consolidated financial statements), and our report dated February 25, 2026 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Houston, Texas

February 25, 2026

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars except share amounts)	2025	2024
ASSETS		
Current assets		
Cash and cash equivalents	\$ 377,196	\$ 423,569
Accounts receivable, net	346,759	272,530
Inventories	Note E 57,284	54,858
Prepaid expenses	35,473	34,322
Total current assets	816,712	785,279
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of \$15,068,149 in 2025 and \$13,811,539 in 2024	Note D 8,136,346	8,054,653
Operating lease assets	Note T 805,464	777,536
Deferred charges and other assets	74,104	50,011
Total assets	\$ 9,832,626	\$ 9,667,479
LIABILITIES AND EQUITY		
Current liabilities		
Current maturities of long-term debt, finance lease	Note F \$ 2,514	\$ 871
Accounts payable	572,183	472,165
Income taxes payable	18,209	19,003
Other taxes payable	28,295	31,685
Operating lease liabilities	Note T 278,834	253,208
Other accrued liabilities	120,755	117,802
Current asset retirement obligations	Note G 41,959	48,080
Total current liabilities	1,062,749	942,814
Long-term debt, including finance lease obligation	Note F 1,382,566	1,274,502
Asset retirement obligations	Note G 970,908	960,804
Deferred credits and other liabilities	263,596	274,345
Non-current operating lease liabilities	Note T 537,773	537,381
Deferred income taxes	Note H 378,337	335,790
Total liabilities	\$ 4,595,929	\$ 4,325,636
Equity		
Cumulative Preferred Stock, par \$100, authorized 400,000 shares, none issued	\$ —	\$ —
Common Stock, par \$1.00, authorized 450,000,000 shares, issued 195,100,628 shares at December 31, 2025 and 195,100,628 shares at December 31, 2024	195,101	195,101
Capital in excess of par value	859,633	848,950
Retained earnings	6,691,318	6,773,289
Accumulated other comprehensive loss	Note N (554,227)	(628,072)
Treasury stock	(2,073,445)	(1,995,018)
Murphy Shareholders' Equity	5,118,380	5,194,250
Noncontrolling interest	118,317	147,593
Total equity	5,236,697	5,341,843
Total liabilities and equity	\$ 9,832,626	\$ 9,667,479

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)

	2025	2024	2023
Revenues and other income			
Revenue from production	\$ 2,689,845	\$ 3,014,856	\$ 3,376,639
Sales of purchased natural gas	–	3,742	72,215
Total revenue from sales to customers	2,689,845	3,018,598	3,448,854
Gain (loss) on derivative instruments	5,927	(1,707)	–
Gain on sale of assets and other operating income	23,051	11,583	11,293
Total revenues and other income	2,718,823	3,028,474	3,460,147
Costs and expenses			
Lease operating expenses	765,240	936,960	784,391
Severance and ad valorem taxes	39,238	39,162	42,787
Transportation, gathering and processing	199,693	210,827	232,985
Costs of purchased natural gas	–	3,147	51,682
Exploration expenses, including undeveloped lease amortization	111,670	133,538	234,776
Selling and general expenses	137,332	110,085	117,306
Depreciation, depletion and amortization	977,753	865,753	861,602
Accretion of asset retirement obligations	57,730	52,511	46,059
Impairment of assets	115,002	62,909	–
Other operating expense	13,928	10,989	46,530
Total costs and expenses	2,417,586	2,425,881	2,418,118
Operating income from continuing operations	301,237	602,593	1,042,029
Other income (loss)			
Other income (loss)	(22,299)	70,902	(8,587)
Interest expense, net	(96,072)	(105,926)	(112,373)
Total other loss	(118,371)	(35,024)	(120,960)
Income from continuing operations before income taxes	182,866	567,569	921,069
Income tax expense	44,552	78,272	195,921
Income from continuing operations	138,314	489,297	725,148
Income (loss) from discontinued operations, net of income taxes	485	(2,812)	(1,467)
Net income including noncontrolling interest	138,799	486,485	723,681
Less: Net income attributable to noncontrolling interest	34,565	79,314	62,122
NET INCOME ATTRIBUTABLE TO MURPHY	\$ 104,234	\$ 407,171	\$ 661,559
NET INCOME (LOSS) PER COMMON SHARE - BASIC			
Continuing operations	\$ 0.73	\$ 2.73	\$ 4.27
Discontinued operations	–	(0.02)	(0.01)
Net income	\$ 0.73	\$ 2.71	\$ 4.26
NET INCOME (LOSS) PER COMMON SHARE - DILUTED			
Continuing operations	\$ 0.72	\$ 2.72	\$ 4.23
Discontinued operations	–	(0.02)	(0.01)
Net income	\$ 0.72	\$ 2.70	\$ 4.22
Cash dividends per common share	\$ 1.300	\$ 1.200	\$ 1.100
Average common shares outstanding (thousands)			
Basic	143,124	150,011	155,234
Diluted	144,025	151,027	156,646

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years Ended December 31 (Thousands of dollars)	2025	2024	2023
Net income including noncontrolling interest	\$ 138,799	\$ 486,485	\$ 723,681
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	73,993	(134,692)	36,598
Retirement and postretirement benefit plans	(148)	27,737	(23,029)
Other comprehensive income (loss)	73,845	(106,955)	13,569
Comprehensive income including noncontrolling interest	212,644	379,530	737,250
Less: Comprehensive income attributable to noncontrolling interest	34,565	79,314	62,122
COMPREHENSIVE INCOME ATTRIBUTABLE TO MURPHY	\$ 178,079	\$ 300,216	\$ 675,128

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2025	2024	2023
Operating Activities			
Net income including noncontrolling interest	\$ 138,799	\$ 486,485	\$ 723,681
Adjustments to reconcile net income to net cash provided by continuing operations activities			
Depreciation, depletion and amortization	977,753	865,753	861,602
Unsuccessful exploration well costs and previously suspended exploration costs	30,095	73,201	169,795
Deferred income tax expense	34,673	72,434	179,823
Impairment of assets	115,002	62,909	–
Accretion of asset retirement obligations	57,730	52,511	46,059
Long-term non-cash compensation	45,128	45,057	61,953
Amortization of undeveloped leases	11,634	9,587	10,925
(Income) loss from discontinued operations	(485)	2,812	1,467
Unrealized (gain) loss on derivative instruments	(1,706)	1,707	–
Contingent consideration payment	–	–	(139,574)
Unrealized loss on contingent consideration	–	–	7,113
Other operating activities, net	(86,763)	(18,349)	(74,728)
Net decrease (increase) in non-cash working capital	(74,052)	74,883	(99,361)
Net cash provided by continuing operations activities	1,247,808	1,728,990	1,748,755
Investing Activities			
Property additions and dry hole costs ¹	(1,020,611)	(900,108)	(1,066,015)
Acquisition of oil and natural gas properties ¹	(29,034)	(8,056)	(35,578)
Proceeds from sales of property, plant and equipment	20,719	–	102,913
Net cash required by investing activities	(1,028,926)	(908,164)	(998,680)
Financing Activities			
Retirement of debt	–	(650,112)	(498,175)
Early redemption of debt cost	–	(15,700)	–
Debt issuance	–	600,000	–
Debt issuance cost	–	(10,145)	–
Borrowings on revolving credit facility	550,000	350,000	600,000
Repayment of revolving credit facility	(450,000)	(350,000)	(600,000)
Issue costs of revolving credit facility	(418)	(14,718)	(20)
Repurchase of common stock	(102,620)	(301,350)	(150,022)
Cash dividends paid	(186,205)	(179,961)	(170,978)
Distributions to noncontrolling interest	(63,841)	(118,580)	(29,382)
Withholding tax on stock-based incentive awards	(9,743)	(25,310)	(14,276)
Finance lease obligation payments	(1,238)	(665)	(622)
Contingent consideration payment	–	–	(60,243)
Net cash required by financing activities	(264,065)	(716,541)	(923,718)
Effect of exchange rate changes on cash and cash equivalents	(1,190)	2,210	(1,246)
Net increase (decrease) in cash and cash equivalents	(46,373)	106,495	(174,889)
Cash and cash equivalents at beginning of period	423,569	317,074	491,963
Cash and cash equivalents at end of period	\$ 377,196	\$ 423,569	\$ 317,074

¹ Prior period amounts have been reclassified to conform to current period presentation.

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 (Thousands of dollars except number of shares)	2025	2024	2023
Common Stock			
Balance at beginning and end of year - par \$1.00, authorized 450,000,000 shares at December 31, 2025, 2024 and 2023, issued 195,100,628 shares at December 31, 2025, 2024 and 2023	\$ 195,101	\$ 195,101	\$ 195,101
Capital in Excess of Par Value			
Balance at beginning of year	848,950	880,297	893,578
Restricted stock transactions and other	(32,165)	(70,539)	(42,667)
Share-based compensation	42,848	39,192	29,386
Balance at end of year	859,633	848,950	880,297
Retained Earnings			
Balance at beginning of year	6,773,289	6,546,079	6,055,498
Net income attributable to Murphy	104,234	407,171	661,559
Cash dividends paid	(186,205)	(179,961)	(170,978)
Balance at end of year	6,691,318	6,773,289	6,546,079
Accumulated Other Comprehensive Loss			
Balance at beginning of year	(628,072)	(521,117)	(534,686)
Foreign currency translation gain (loss), net of income taxes	73,993	(134,692)	36,598
Retirement and postretirement benefit plans, net of income taxes	(148)	27,737	(23,029)
Balance at end of year	(554,227)	(628,072)	(521,117)
Treasury Stock			
Balance at beginning of year	(1,995,018)	(1,737,566)	(1,614,717)
Repurchase of common stock	(100,849)	(302,681)	(151,241)
Awarded restricted stock, net of forfeitures	22,422	45,229	28,392
Balance at end of year - 52,315,476 shares of common stock in 2025, 49,255,504 shares of common stock in 2024 and 42,351,986 shares of common stock in 2023	(2,073,445)	(1,995,018)	(1,737,566)
Murphy Shareholders' Equity	5,118,380	5,194,250	5,362,794
Noncontrolling Interest			
Balance at beginning of year	147,593	186,859	154,119
Net income attributable to noncontrolling interest	34,565	79,314	62,122
Distributions to noncontrolling interest owners	(63,841)	(118,580)	(29,382)
Balance at end of year	118,317	147,593	186,859
Total Equity	\$ 5,236,697	\$ 5,341,843	\$ 5,549,653

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

These notes are an integral part of the consolidated financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages [73-110](#) of the Form 10-K report.

Note A - Significant Accounting Policies

NATURE OF BUSINESS - Murphy Oil Corporation is an international oil and natural gas company that conducts its business through various operating subsidiaries. The Company primarily produces oil and natural gas in the U.S. and Canada and conducts oil and natural gas exploration activities worldwide.

BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION - The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries and are presented in conformity with GAAP. Undivided interests in oil and natural gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Murphy reports 100% of the sales volume, revenues, costs, assets and liabilities including the 20% noncontrolling interest in MP GOM in accordance with accounting for noncontrolling interest as prescribed by Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810-10-45, "Consolidations". Other investments are generally carried at cost. Intercompany accounts and transactions are eliminated.

USE OF ESTIMATES - Preparing the financial statements of the Company in accordance with GAAP requires management to make a number of estimates and assumptions that affect the reporting of amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

REVENUE RECOGNITION - Revenues from sales of oil and natural gas are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer; the amount of revenue recognized reflects the consideration expected in exchange for those commodities. The Company measures revenue based on consideration specified in a contract and excludes taxes and other amounts collected on behalf of third parties. Revenues from the production of oil and natural gas properties, in which Murphy shares in the undivided interest with other producers, are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company's actual natural gas sales volumes differ from its proportional share of production from the well. The Company follows the sales method of accounting for these natural gas imbalances. The Company records a liability for natural gas imbalances when it has sold more than its working interest of natural gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2025 and 2024, the liabilities for natural gas balancing were immaterial. Gains and losses on asset disposals or retirements are included in net income/(loss) as a component of revenues.

CASH EQUIVALENTS - Short-term investments, which include government securities and other instruments with government securities as collateral, that are highly liquid and have a maturity of three months or less from the date of purchase are classified as cash equivalents.

MARKETABLE SECURITIES - The Company classifies investments in marketable securities as available-for-sale or held-to-maturity. The Company does not have any investments classified as trading securities. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive loss. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security. Dividend and interest income is recognized when earned. Unrealized losses considered to be other than temporary are recognized in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices.

ACCOUNTS RECEIVABLE - At December 31, 2025 and 2024, the Company's accounts receivable primarily consisted of amounts owed to the Company by customers for sales of crude oil and natural gas and operating costs related to joint venture partners working interest share. Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers, joint venture partners and historical write-off experience. Any trade accounts receivable balances written off are charged against the allowance for doubtful accounts. The Company has not experienced any significant credit-related losses in the past three years.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note A - Significant Accounting Policies (Continued)

INVENTORIES - Amounts included in the Consolidated Balance Sheets include unsold crude oil production and materials and supplies associated with oil and natural gas production operations. Unsold crude oil production is carried in inventory at the lower of cost (applied on a first-in, first-out basis and including costs incurred to bring the inventory to its existing condition), or market. Materials and supplies inventories are valued at the lower of average cost or estimated market value and generally consist of tubulars and other drilling equipment. See [Note E](#).

PROPERTY, PLANT AND EQUIPMENT - The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on undeveloped property, the leasehold cost is transferred to proved properties. Costs of undeveloped leases associated with unproved properties are expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is usually dependent on whether further exploratory or appraisal wells find a sufficient quantity of additional reserves. The Company continues to capitalize exploratory well costs in "Property, plant and equipment" when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized.

Oil and natural gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment is assessed when there is an indication that the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to its fair value. See [Note D](#) for further discussion of impairment charges.

The Company records a liability for ARO equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled, or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and natural gas production facilities, plugging and abandoning wells and restoring sites are charged against the related liability. Any difference between costs incurred upon settlement of an ARO and the recorded liability is recognized as a gain or loss in the Company's earnings. See [Note G](#) for further discussion.

Depreciation and depletion of producing oil and natural gas properties are recorded based on units of production. Unit rates are computed for unamortized development drilling and completion costs using proved developed reserves and acquisition costs are amortized over proved reserves. Proved reserves are estimated by the Company's engineers and are subject to future revisions based on the availability of additional information.

CAPITALIZED INTEREST - Interest associated with borrowings from third parties is capitalized on significant oil and natural gas development projects when the expected development period extends for one year or more. Interest capitalized is credited in the Consolidated Statements of Operations and is added to the cost of the underlying asset for the development project in "Property, plant and equipment" in the Consolidated Balance Sheets. Capitalized interest is amortized over the useful life of the asset in the same manner as other development costs.

LEASES - At inception, contracts are assessed for the presence of a lease according to the criteria of ASC 842, "Leases". If a lease is present, further criteria is assessed to determine if the lease should be classified as an operating or finance lease. Operating leases are presented on the Consolidated Balance Sheets as "Operating lease assets" with the corresponding lease liabilities presented in "Operating lease liabilities" and "Non-current operating lease liabilities". Finance lease assets are presented on the Consolidated Balance Sheets within

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note A - Significant Accounting Policies (Continued)

"Property, plant and equipment", with the corresponding liabilities presented in "Current maturities of long-term debt, finance lease" and "Long-term debt, including finance lease obligation".

Generally, lease liabilities are recognized at commencement and based on the present value of the future minimum lease payments to be made over the lease term. Lease assets are then recognized based on the value of the lease liabilities. Where implicit lease rates are not determinable, the minimum lease payments are discounted using the Company's collateralized incremental borrowing rates.

Operating leases are expensed according to their nature and recognized in "Lease operating expenses", "Selling and general expenses", "Transportation, gathering and processing", "Exploration expenses", "Other operating expenses" or capitalized in the consolidated financial statements. Finance leases are depreciated with the relevant expenses recognized in "Depreciation, depletion and amortization" and "Interest expense, net" on the Consolidated Statements of Operations.

ENVIRONMENTAL LIABILITIES - A liability for environmental matters is established when it is probable that an environmental obligation exists, and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded. If no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

INCOME TAXES - The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities arising from differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. The Company routinely assesses the realizability of deferred tax assets based on available evidence, including assumptions of future taxable income, tax planning strategies and other pertinent factors. A deferred tax asset valuation allowance is recorded when evidence indicates that it is more likely than not that all or a portion of these deferred tax assets will not be realized in a future period.

The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

FOREIGN CURRENCY - Local currency is the functional currency used for recording operations in Canada and former refining and marketing activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Exchange gains or losses from transactions in a currency other than the functional currency are included in earnings as part of interest and other income (loss). Gains or losses from translating foreign functional currencies into U.S. dollars are included in "Accumulated Other Comprehensive Loss" in the Consolidated Statements of Stockholders' Equity.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES - The fair value of a derivative instrument is recognized as an asset or liability in the Consolidated Balance Sheets. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or it may decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. Certain physical delivery sale and purchase contracts are entered into in the normal course of business and qualify for, and are designated under, the normal purchase and normal sale scope exception provided by ASC 815, "Derivatives and Hedging". Accordingly, these contracts are not accounted for as derivative instruments or recorded at fair value in the Consolidated Balance Sheets. Revenues and expenses associated with these contracts are recognized in net income (loss) when the underlying physical transactions occur.

The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its risk management objectives and strategy. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis, whether a derivative instrument accounted for as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. The change in the fair value of a qualifying fair value hedge is recorded in earnings along with the gain or loss on the hedged item. The effective portion of the change in the fair value of a qualifying cash flow hedge is recorded in

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note A - Significant Accounting Policies (Continued)

"Accumulated other comprehensive loss" in the Consolidated Balance Sheets until the hedged item is recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued, and the gain or loss recorded in "Accumulated other comprehensive loss" is recognized immediately in earnings. All commodity price derivatives for the periods provided are not designated as cash flow or fair value hedges and therefore changes in fair value are recognized in earnings.

FAIR VALUE MEASUREMENTS - The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. Fair value is determined using various techniques depending on the availability of observable inputs. Level 1 inputs include quoted prices in active markets for identical assets or liabilities. Level 2 inputs include observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants. See [Note O](#).

STOCK-BASED COMPENSATION

Equity-Settled Awards - The fair value of awarded stock options, restricted stock units and other stock-based compensation that are settled with Company shares is determined based on a combination of management assumptions and the market value of the Company's common stock. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock units (PSUs) with market based conditions, and expense is recognized over the three-year vesting period. The fair value of PSUs with performance-based conditions and time-based restricted stock units (RSUs) is determined based on the price of Company stock on the date of grant and expense is recognized over the vesting period.

The Company uses the Black-Scholes option pricing model for computing the fair value of equity-settled stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock price. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company estimates the number of stock options and PSUs that will not vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for as an adjustment to expense, when known.

Cash-Settled Awards - The Company accounts for stock appreciation rights (SARs) and cash-settled restricted time-based stock units (CRSUs) as liability awards. Expense associated with these awards is recognized over the vesting period based on the latest available estimate of the fair value of the awards, which is generally determined using a Black-Scholes method for SARs and the period-end price of the Company's common stock for time-based CRSUs. When SARs are exercised and when CRSUs settle, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards. See [Note I](#).

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS - The Company recognizes the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of its defined benefit and other postretirement benefit plans in the Consolidated Balance Sheets. Changes in the funded status which have not yet been recognized in the Consolidated Statements of Operations are recorded net of tax in "Accumulated other comprehensive loss". The remaining amounts in "Accumulated other comprehensive loss" include net actuarial losses and prior service (cost) credit. See [Note J](#).

NET INCOME (LOSS) PER COMMON SHARE - Basic net income (loss) per common share is computed by dividing net income (loss) for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income (loss) per common share is computed by dividing net income (loss) for each reporting period by the weighted average number of common shares outstanding during the period plus the effects of all potentially dilutive common shares. Dilutive securities are not included in the computation of diluted income (loss) per share when a net loss occurs, as the inclusion would have the effect of reducing the diluted loss per share. See [Note L](#).

Note B - New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Income Tax Disclosures. In December 2023, the FASB issued Accounting Standards Update (ASU) 2023-09 *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*. The update requires financial statements to include consistent categories and greater disaggregation of information in the rate reconciliation, as well as income taxes paid disaggregated by jurisdiction. The Company adopted this standard in the fourth quarter of

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note B - New Accounting Principles and Recent Accounting Pronouncements (Continued)

2025. The adoption did not affect the calculation of income tax expense. These new disclosure requirements are applied retrospectively to all prior periods included in the financial statements. Refer to [Note H](#).

Recent Accounting Pronouncements

Expense Disaggregation Disclosures. In November 2024, the FASB issued ASU 2024-03 *Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses*. The standard becomes effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. The standard requires specified information about certain costs and expenses presented on the face of the income statement to be further disaggregated in the notes to the financial statements. In addition, the standard requires certain expense and cost information that is not separately disaggregated to be qualitatively described. We are currently evaluating our expense categories and underlying cost components to identify the quantitative and qualitative disclosures that will be required upon adoption. We expect this ASU to only impact our disclosures with no impacts on our results of operations, cash flows and financial condition.

The Company evaluates the applicability and impact of all ASUs. ASUs not specifically discussed above were assessed and determined to be not applicable, previously disclosed, or not material upon adoption.

Note C - Revenue from Contracts with Customers

Nature of Goods and Services

The Company explores for and produces oil and natural gas in select basins around the world. The Company's revenue from sales of oil and natural gas production activities is primarily subdivided into two key geographic segments: the U.S. and Canada. Additionally, revenue from sales to customers is generated from three primary revenue streams: crude oil, natural gas and NGLs.

For operated oil and natural gas production where a non-operated working interest owner does not take in kind its proportionate interest in the produced commodity, the Company acts as an agent for the working interest owner and recognizes revenue only for its own share of the commingled production. The exception to this is the reporting of the noncontrolling interest in MP GOM as prescribed by GAAP.

U.S. - In the U.S., the Company primarily produces oil and natural gas from fields in the Eagle Ford Shale area of South Texas and in the Gulf of America. Revenue is generally recognized when oil and natural gas is transferred to the customer at the delivery point. Revenue recognized is largely index-based with price adjustments for floating market differentials.

Canada - In Canada, contracts include long-term floating commodity index-priced and natural gas physical forward sales fixed-price contracts. For the offshore business in Canada, contracts are based on index prices and revenue is recognized at the time of vessel load based on the volumes on the bill of lading and point of custody transfer. The Company also purchases natural gas in Canada to meet certain sales commitments.

Disaggregation of Revenue

The Company reviews performance based on two key geographical segments and between onshore and offshore sources of revenue within these geographies.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note C - Revenue from Contracts with Customers (Continued)

The Company's revenues and other income for each of the three years presented were as follows.

<i>(Thousands of dollars)</i>	Years Ended December 31,		
	2025	2024	2023
Net crude oil and condensate revenue			
United States - Onshore	\$ 617,358	\$ 586,584	\$ 676,139
United States - Offshore ¹	1,355,527	1,777,723	2,072,353
Canada - Onshore	61,715	70,855	78,088
Canada - Offshore	187,030	193,961	78,650
Other	5,713	6,537	11,022
Total crude oil and condensate revenue	<u>2,227,343</u>	<u>2,635,660</u>	<u>2,916,252</u>
Net natural gas liquids revenue			
United States - Onshore	41,518	32,853	33,178
United States - Offshore ¹	33,029	38,858	47,434
Canada - Onshore	5,626	7,454	8,914
Total natural gas liquids revenue	<u>80,173</u>	<u>79,165</u>	<u>89,526</u>
Net natural gas revenue			
United States - Onshore	35,524	17,443	21,346
United States - Offshore ¹	70,968	50,329	71,332
Canada - Onshore	275,837	232,259	278,183
Total natural gas revenue	<u>382,329</u>	<u>300,031</u>	<u>370,861</u>
Revenue from production	<u>2,689,845</u>	<u>3,014,856</u>	<u>3,376,639</u>
Sales of purchased natural gas ²			
Canada - Onshore	–	3,742	72,215
Total sales of purchased natural gas	<u>–</u>	<u>3,742</u>	<u>72,215</u>
Total revenue from sales to customers	<u>2,689,845</u>	<u>3,018,598</u>	<u>3,448,854</u>
Gain (loss) on derivative instruments	5,927	(1,707)	–
Gain on sale of assets and other operating income	23,051	11,583	11,293
Total revenues and other income	<u>\$ 2,718,823</u>	<u>\$ 3,028,474</u>	<u>\$ 3,460,147</u>

¹ Includes revenue attributable to the noncontrolling interest in MP GOM.

² Purchases of natural gas are reported on a gross basis when Murphy takes control of the product and has risks and rewards of ownership. Sales of natural gas are reported when the contractual performance obligations are satisfied. This occurs at the time the product is delivered to a third party purchaser at the contractually determinable price.

Contract Balances and Asset Recognition

As of December 31, 2025 and 2024, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet from continuing operations, were \$165.3 million and \$178.3 million, respectively. Payment terms for the Company's sales vary across contracts and geographical regions, with the majority of the cash receipts required within 30 days of billing. Based on a forward-looking expected loss model in accordance with ASU 2016-13, the Company did not recognize any impairment losses on receivables or contract assets arising from customer contracts during the reporting periods.

The Company has not entered into any revenue contracts that have financing components as of December 31, 2025, 2024 or 2023.

The Company does not employ sales incentive strategies such as commissions or bonuses for obtaining sales contracts. For the periods presented, the Company did not identify any assets to be recognized associated with the costs to obtain a contract with a customer.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note C - Revenue from Contracts with Customers (Continued)

Performance Obligations

The Company recognizes oil and natural gas revenue when it satisfies a performance obligation by transferring control over a commodity to a customer. Judgment is required to determine whether some customers simultaneously receive and consume the benefit of commodities. As a result of this assessment for the Company, each unit of measure of the specified commodity is considered to represent a distinct performance obligation that is satisfied at a point in time upon the transfer of control of the commodity.

For contracts with market or index-based pricing, which represent the majority of sales contracts, the Company has elected the allocation exception and allocates the variable consideration to each single performance obligation in the contract. As a result, there is no price allocation to unsatisfied remaining performance obligations for delivery of commodity product in subsequent periods.

The Company has entered into several long-term, fixed-price contracts in Canada. The underlying reason for entering a fixed price contract is generally unrelated to anticipated future prices or other observable data and serves a particular purpose in the Company's long-term strategy.

As of December 31, 2025, the Company had the following sales contracts in place which are expected to generate revenue from sales to customers for a period over 12 months starting at the inception of the contract.

Location	Commodity	End Date	Description	Approximate Volumes
U.S.	Natural Gas and NGLs	Q2 2030	Deliveries from dedicated acreage in Eagle Ford Shale	As produced
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at USD index pricing	49 MMCF/D
Canada	Natural Gas	Q4 2027	Contracts to sell natural gas at USD index pricing	30 MMCF/D
Canada	Natural Gas	Q4 2028	Contracts to sell natural gas at USD index pricing	10 MMCF/D
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at CAD fixed pricing	50 MMCF/D
Canada	Natural Gas	Q4 2027	Contracts to sell natural gas at CAD fixed pricing	9 MMCF/D
Canada	NGLs	Q4 2026	Contracts to sell NGLs at CAD index pricing	As produced

The fixed price contracts above are accounted for as normal sales and purchases for accounting purposes.

Note D - Property, Plant and Equipment

The Company's property, plant and equipment assets for the respective periods are presented as follows:

	December 31, 2025		December 31, 2024	
	Cost	Net	Cost	Net
<i>(Thousands of dollars)</i>				
Exploration and production ¹	\$ 23,042,373	\$ 8,099,291 ²	\$ 21,716,358	\$ 8,021,620 ²
Corporate and other	162,122	37,055	149,834	33,033
Property, plant and equipment	\$ 23,204,495	\$ 8,136,346	\$ 21,866,192	\$ 8,054,653
¹ Includes unproved mineral rights as follows:	\$ 229,759	\$ 99,729	\$ 283,015	\$ 151,341

² Includes \$12,050 in 2025 and \$13,335 in 2024 related to administrative assets and support equipment.

Exploratory Wells

Under FASB guidance, exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well, and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

At December 31, 2025, 2024 and 2023, the Company had total capitalized drilling costs pending the determination of proved reserves of \$191.8 million, \$72.1 million and \$49.1 million, respectively. The following table reflects the net changes in capitalized exploratory well costs for each of the three years presented.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note D - Property, Plant and Equipment (Continued)

<i>(Thousands of dollars)</i>	2025	2024	2023
Beginning balance at January 1	\$ 72,055	\$ 49,118	\$ 171,860
Additions pending the determination of proved reserves	119,766	49,408	48
Reclassifications to proved properties based on the determination of proved reserves	–	–	(82,185)
Capitalized exploration well costs charged to expense	–	(26,471)	(40,605)
Ending balance at December 31	<u>\$ 191,821</u>	<u>\$ 72,055</u>	<u>\$ 49,118</u>

Capital additions of \$119.8 million, for the year ended December 31, 2025, were mainly for the Hai Su Vang-2X (Golden Sea Lion), Block 15-2/17, and Lac Da Hong-1X (Pink Camel), Block 15-1/05 exploration wells in Vietnam. The Lac Da Hong-1X (Pink Camel), Block 15-1/05 exploration well, in Vietnam, encountered 106 feet of net oil pay from one reservoir and continues to progress post-drill evaluations. Capital additions also included Banjo #1 (Mississippi Canyon 385) and Cello #1 (Mississippi Canyon 385) exploration wells in the Gulf of America and Bubale-1X (Block CI-709) and Caracal-1X (Block CI-102) exploration wells in Côte d'Ivoire.

Subsequent to year end, Murphy announced the successful discoveries of the Banjo #1 (Mississippi Canyon 385) and Cello #1 (Mississippi Canyon 385) exploration wells, which encountered 50 feet and 30 feet of net pay, respectively. The Company also announced the results of two exploration wells in Côte d'Ivoire at the Civette-1X (Block CI-502) exploration well, which encountered non-commercial hydrocarbons, and at the Caracal-1X (Block CI-102) exploration well, which will be plugged and abandoned as a dry hole after encountering non-commercial hydrocarbon shows. A portion of the Civette-1X dry hole charge was recorded in 2025. The remainder of Civette-1X and all charges related to the Caracal-1X well will be recorded in the first quarter of 2026.

Capital additions of \$49.4 million, for the year ended December 31, 2024, were mainly for the non-operated Ocotillo #1 (Mississippi Canyon 40) exploration well in the Gulf of America and the Hai Su Vang-1X (Golden Sea Lion), Block 15/2-17 exploration well in Vietnam.

Reclassifications to proved properties of \$82.2 million, for the year ended December 31, 2023, were primarily related to Lac Da Vang-4X (Golden Camel), Block 15-1/05 exploration well in Vietnam.

Capitalized well costs charged to dry hole expense were \$26.5 million and \$40.6 million for the years ended 2024 and 2023, respectively. In 2024, costs related to the Hoffe Park #1 (Mississippi Canyon 166) exploration well. In 2023, costs related to the Cholula-1EXP well offshore Mexico and the Oso #1 (Atwater Valley 138) and Chinook #7 (Walker Ridge 425) exploration wells in the Gulf of America.

The preceding table excludes well costs of \$30.1 million, \$46.7 million, and \$129.2 million incurred and expensed directly to dry hole during the years ended 2025, 2024 and 2023, respectively. In 2025, these costs primarily included \$30.0 million for the Civette-1X (Block CI-502) exploration well in Côte d'Ivoire. In 2024, these costs primarily included \$27.6 million for the non-operated Orange #1 (Mississippi Canyon 216) and \$13.4 million for the Sebastian #1 (Mississippi Canyon 387) exploration wells in the Gulf of America. In 2023, the amount primarily included \$82.0 million for the Chinook #7 (Walker Ridge 425) and \$47.2 million for the non-operated Oso #1 (Atwater Valley 138) exploration wells in the Gulf of America.

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well.

<i>(Thousands of dollars)</i>	2025		2024		2023	
	Amount	No. of Wells	Amount	No. of Wells	Amount	No. of Wells
Aging of capitalized well costs						
Zero to one year	\$ 28,384	2	\$ 49,790	5	\$ –	0
One to two years	140,959	6	–	–	–	0
Two to three years	–	–	–	–	2,698	1
Three years or more	22,478	3	22,265	3	46,420	3
	<u>\$ 191,821</u>	<u>11</u>	<u>\$ 72,055</u>	<u>8</u>	<u>\$ 49,118</u>	<u>4</u>

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note D - Property, Plant and Equipment (Continued)

Of the \$163.4 million of exploratory well costs capitalized more than one year at December 31, 2025, \$91.5 million was in Vietnam, \$64.6 million was in the Gulf of America, \$4.6 million was in Canada, and \$2.7 million was in Brunei. In all geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

Property Additions

On July 1, 2025, the Company purchased additional working interests in the Eagle Ford Shale, in acreages primarily operated by Murphy, for \$23.0 million.

During the first quarter of 2025, Murphy purchased the Pioneer FPSO from BW Offshore (UK) Limited for a gross purchase price of \$125.0 million. The FPSO remained on location, supporting operations at the Cascade field (Walker Ridge 206 and 250) and Chinook field (Walker Ridge 469 and 425) in the Gulf of America. BW Offshore (UK) Limited continues to provide operations and maintenance services under a new five-year contract.

Dispositions

In the fourth quarter of 2025, Murphy received a \$12.5 million payment for achieving the first milestone related to the contingent sale of Brunei CA-2 in 2022, which resulted in a \$4.0 million gain on sale of assets. In addition, the revaluation of the final milestone (anticipated in 2031) resulted in a \$6.0 million gain on sale of assets.

In September 2025, Murphy executed a purchase and sale agreement, which closed in October 2025, for the sale of leases in the Ralph and Saylee area of Tilden West for an adjusted sales price of \$8.2 million. No gain or loss was recorded for this sale.

Impairments

In 2025, the Company recognized a pretax impairment charge of \$115.0 million (\$92.0 million excluding NCI) related to the partial write-down of the Dalmatian field, in the Gulf of America, due to reserve reductions, as certain projects in the field were less competitive for capital allocation.

In 2024, the Company recorded a pretax impairment charge of \$62.9 million. In the first quarter of 2024, the Company recorded an impairment charge of \$34.5 million related to the Calliope field, and in the fourth quarter of 2024, the Company recorded an impairment charge of \$28.4 million related to the Nearly Headless Nick field. Both of the impairments were the result of operational issues that led to reserve reductions.

There were no impairments recognized in 2023.

Note E - Inventories

Inventories consisted of the following for the respective periods presented.

	December 31,	
	2025	2024
<i>(Thousands of dollars)</i>		
Unsold crude oil	\$ 17,560	\$ 18,745
Materials and supplies	39,724	36,113
Inventories	\$ 57,284	\$ 54,858

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note F - Financing Arrangements and Debt

Long-term debt for the respective periods presented consisted of the following.

<i>(Thousands of dollars)</i>	December 31,	
	2025	2024
Notes payable		
5.875% notes, due December 2027	\$ 78,899	\$ 78,899
6.375% notes, due July 2028	148,590	148,590
7.050% notes, due May 2029	117,582	117,582
6.000% notes, due October 2032	600,000	600,000
5.875% notes, due December 2042 ¹	339,761	339,761
Total notes payable	1,284,832	1,284,832
Unamortized debt issuance cost and discount on notes payable	(12,406)	(14,336)
Total notes payable, net of unamortized discount	1,272,426	1,270,496
Finance lease obligations, due through November 2034	12,654	4,877
Total debt including current maturities	1,285,080	1,275,373
Senior Unsecured Revolving Credit Facility	100,000	—
Current maturities	(2,514)	(871)
Total long-term debt	\$ 1,382,566	\$ 1,274,502

¹ Coupon rate may fluctuate 25 basis points if rating is periodically downgraded or upgraded by S&P and Moody's.

The amounts of long-term principal repayable over each of the next five years and thereafter are as follows: nil in 2026, \$78.9 million in 2027, \$148.6 million in 2028, \$217.6 million in 2029, nil in 2030 and \$939.8 million thereafter.

The Company also has a shelf registration statement on file with the SEC that permits the offer and sale of debt and/or equity securities through October 15, 2027.

Revolving Credit Facility

As of December 31, 2025, the Company had a \$1.35 billion senior unsecured guaranteed RCF, with a maturity date of October 7, 2029. At December 31, 2025, the Company had \$100.0 million outstanding borrowings under the RCF and \$0.4 million of outstanding letters of credit, which reduced the borrowing capacity of the RCF. At December 31, 2025, the interest rate in effect on borrowings under the facility was 6.04%. At December 31, 2025, the Company was in compliance with all covenants related to the RCF. On the date the Company achieved certain credit ratings (Investment Grade Ratings Date), certain covenants would have been modified as set forth in the RCF. In addition, prior to Investment Grade Ratings Date, the Company would have been required to comply with a maximum consolidated leverage ratio of 3.25x and a minimum consolidated interest coverage ratio of 2.50x. From and after the Investment Grade Ratings Date, the Company will be required to comply with a maximum ratio of consolidated total debt to consolidated total capitalization of 60%. Borrowings under the RCF bore interest at rates based on either the "Alternate Base Rate", the "Adjusted Term Secured Overnight Financing Rate (SOFR) Rate", or the "Adjusted Daily Simple SOFR Rate", respectively, plus the "Applicable Rate". The "Alternate Base Rate" of interest was the highest of (a) the Wall Street Journal prime rate in effect on such day, (b) the New York Federal Reserve Bank Rate in effect on such day plus ½ of 1% and (c) the Adjusted Term SOFR Rate for a one month interest period as published two U.S. Government Securities Business Days prior to such day (or if such day is not a U.S. Government Securities Business Day, the immediately preceding U.S. Government Securities Business Day) plus 1%. The "Adjusted Term SOFR Rate" of interest was equal to (a) the Term SOFR Rate for such Interest Period, plus (b) 0.10%. The "Adjusted Daily Simple SOFR Rate" of interest was equal to (a) the Daily Simple SOFR, plus (b) 0.10%. The "Applicable Rate" of interest meant, for any day, the applicable rate per annum based upon the ratings of Moody's Investors Service, Inc. and Standard and Poor's Rating Services.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note F - Financing Arrangements and Debt (Continued)

Subsequent Event - Revolving Credit Facility

On January 2, 2026, the Company entered into an amended credit agreement governing a \$2.00 billion senior unsecured guaranteed revolving credit facility (Amended RCF), with a maturity date of January 2, 2031. The Amended RCF, which is effective January 2026, extends the borrowing term and increases the borrowing capacity of the previous RCF. All terms of the Amended RCF are substantially similar to the existing credit agreement, with an exception for the following: The "Adjusted Term SOFR Rate" of interest is equal to (a) the Term SOFR Rate for such Interest Period, plus (b) zero. The "Adjusted Daily Simple SOFR Rate" of interest is equal to (a) the Daily Simple SOFR, plus (b) zero. The "Applicable Rate" of interest means, for any day, the applicable rate per annum based upon the ratings of Moody's Investors Service, Inc. and Standard and Poor's Rating Services, respectively. The Company incurred \$12.3 million in transaction costs and recorded the amount to "Deferred charges and other assets" in the Consolidated Balance Sheets, which is being amortized to interest expense over the term of the Amended RCF.

Debt Offering

On October 3, 2024, the Company closed the public offering of \$600.0 million aggregate principal amount of senior notes that bear interest at a rate of 6.000% per annum and mature on October 1, 2032. The Company incurred transaction costs of \$10.1 million on the issuance of these notes. The Company pays interest semi-annually on April 1 and October 1 of each year. The proceeds of the \$600.0 million notes were used to fund the repurchase and repayment of debt during the fourth quarter of 2024 to achieve a debt-neutral transaction.

Subsequent Event - Debt Offering

On January 23, 2026, the Company closed a public offering of \$500.0 million aggregate principal amount of its senior notes that bear interest at a rate of 6.500% per annum and mature on February 15, 2034. The Company has incurred transaction costs of \$8.3 million on the issuance of these new notes. The Company will pay interest semi-annually on August 15 and February 15 of each year, beginning August 15, 2026. The proceeds of the \$500.0 million notes were used to fund the repurchase and repayment of debt and related fees, as well as for general corporate purposes.

Debt Extinguishment

In December 2024, the Company redeemed \$79.0 million of the 2027 Notes. The total cost of the debt extinguishment of \$1.2 million, consisting of cash costs of \$0.8 million and non-cash costs of \$0.4 million, is included in "Interest expense, net" on the Consolidated Statements of Operations for the year ended December 31, 2024.

In October 2024, the Company tendered an aggregate \$521.1 million of its notes, comprised of: \$258.8 million of the 2027 Notes, \$200.2 million of the 2028 Notes and \$62.1 million of the 2029 Notes. The total cost of the debt extinguishment of \$18.2 million, consisting of cash costs of \$14.9 million and non-cash costs of \$3.3 million, is included in "Interest expense, net" on the Consolidated Statements of Operations for the year ended December 31, 2024.

In May 2024, the Company paid a total of \$50.5 million to complete the open market repurchases of \$26.5 million aggregate principal of its 2027 Notes and \$23.5 million aggregate principal of its 2028 Notes. The total cost of debt extinguishment of \$0.9 million, consisting of cash costs of \$0.5 million and non-cash costs of \$0.4 million, is included in "Interest expense, net" on the Consolidated Statements of Operations for the year ended December 31, 2024.

Subsequent Event - Debt Extinguishment

On January 23, 2026, the Company redeemed the remaining \$78.9 million principal amount outstanding of its 2027 Notes and \$148.6 million of its 2028 Notes, for an aggregate \$227.5 million. The total cost of the debt extinguishment of \$3.5 million consisted of cash costs of \$2.5 million and non-cash costs of \$1.0 million.

Note G - Asset Retirement Obligations

The ARO liabilities recognized by the Company are related to the estimated costs to dismantle and abandon its producing oil and natural gas properties and related equipment.

A reconciliation of the beginning and ending aggregate carrying amount of the ARO for the respective periods presented is shown in the following table.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note G - Asset Retirement Obligations (Continued)

<i>(Thousands of dollars)</i>	2025	2024
Balance at beginning of year	\$ 1,008,884	\$ 914,763
Accretion	57,730	52,511
Liabilities incurred	20,744	25,619
Revisions of previous estimates	(12,094)	29,279
Liabilities settled	(70,829)	(1,898)
Changes due to translation of foreign currencies	8,432	(11,390)
Balance at end of period	1,012,867	1,008,884
Current portion of liability	(41,959)	(48,080)
Non-current portion of liability	\$ 970,908	\$ 960,804

The estimation of future ARO is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that may be required in future periods due to the availability of additional information such as: prices for oil field services, technological changes, governmental requirements and other factors.

Note H - Income Taxes

The components of income (loss) from continuing operations before income taxes for each of the three years presented and income tax expense (benefit) attributable thereto were as follows.

<i>(Thousands of dollars)</i>	2025	2024	2023
Income (loss) from continuing operations before income taxes			
United States	\$ 195,245	\$ 468,202	\$ 901,761
Foreign	(12,379)	99,367	19,308
Total	\$ 182,866	\$ 567,569	\$ 921,069
Income tax expense			
Current tax expense			
U.S. State and Local	\$ 468	\$ 1,153	\$ 2,916
Foreign	9,411	4,685	13,182
Total current tax expense	9,879	5,838	16,098
Deferred tax expense			
U.S. Federal	37,825	55,377	170,115
U.S. State and Local	(1,214)	(5,641)	3,706
Foreign	(1,938)	22,698	6,002
Total deferred tax expense	34,673	72,434	179,823
Total income tax expense			
U.S. Federal	37,825	55,377	170,115
U.S. State and Local	(746)	(4,488)	6,622
Foreign	7,473	27,383	19,184
Total income tax expense	\$ 44,552	\$ 78,272	\$ 195,921

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note H - Income Taxes (Continued)

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company's income tax expense for each of the three years presented.

<i>(Thousands of dollars)</i>	2025		2024		2023	
	Amount	Percent	Amount	Percent	Amount	Percent
Income tax expense based on the U.S. statutory tax rate	\$ 38,402	21.0 %	\$ 119,190	21.0 %	\$ 193,424	21.0 %
Domestic Federal						
Tax Credits						
Research and development tax credits	2,521	1.4	(6,841)	(1.2)	(8,805)	(1.0)
Nontaxable or Nondeductible Items						
Tax effect on income attributable to NCI	(7,259)	(4.0)	(16,656)	(2.9)	(13,046)	(1.4)
U.S. tax benefit on certain foreign upstream investments	–	–	(33,677)	(5.9)	–	–
Other	(397)	(0.2)	2,398	0.4	(293)	–
Share-based payment awards	5,595	3.1	2,340	0.4	2,636	0.3
State and Local Income Taxes, Net of Federal Income Tax Effect ¹	(589)	(0.3)	(3,546)	(0.6)	4,725	0.5
Foreign Tax Effects						
Canada						
Statutory tax rate differential	2,629	1.4	5,428	1.0	3,732	0.4
Research and development tax credits	(3,875)	(2.1)	(3,547)	(0.6)	(3,982)	(0.4)
Other Foreign jurisdictions						
Statutory tax rate differential	4,960	2.7	9,127	1.6	2,844	0.3
Changes in valuation allowances						
Côte d'Ivoire	13,140	7.2	–	–	–	–
Other Foreign Jurisdictions	(2,922)	(1.6)	2,636	0.5	10,853	1.2
Other	(5,825)	(3.2)	(532)	(0.2)	1,377	0.1
Worldwide Changes in Unrecognized Tax Benefits	(1,828)	(1.0)	1,952	0.3	2,456	0.3
Effective Tax Rate	<u>\$ 44,552</u>	<u>24.4 %</u>	<u>\$ 78,272</u>	<u>13.8 %</u>	<u>\$ 195,921</u>	<u>21.3 %</u>

¹ State taxes primarily include Texas and Louisiana.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note H - Income Taxes (Continued)

The following table displays cash taxes paid, net of refunds, for each of the three years presented.

<i>(Thousands of dollars)</i>	2025	2024	2023
U.S. State and Local			
Alabama	\$ (1,868)	\$ —	\$ 4,838
Texas	1,500	2,300	1,079
Other	50	—	51
Total U.S. State and Local	(318)	2,300	5,968
Foreign			
Canada	2,929	6,480	3,553
Canada - Alberta	2,809	3,269	1,756
Brunei	681	599	1,079
Total Foreign	6,419	10,348	6,388
Total	\$ 6,101	\$ 12,648	\$ 12,356

An analysis of the Company's deferred tax assets and deferred tax liabilities for the respective periods presented showing the tax effects of significant temporary differences follows.

<i>(Thousands of dollars)</i>	2025	2024
Deferred tax assets		
Property and leasehold costs	\$ 235,509	\$ 225,379
Liabilities for dismantlements	40,242	36,719
Postretirement and other employee benefits	66,418	66,293
U. S. net operating loss	224,956	289,594
Investment in partnership	20,307	9,096
Other deferred tax assets ¹	97,660	100,352
Total gross deferred tax assets	685,092	727,433
Less: Valuation allowance	(157,807)	(149,498)
Net deferred tax assets	527,285	577,935
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	(5,000)	(5,000)
Accumulated depreciation, depletion and amortization	(812,727)	(811,178)
Other deferred tax liabilities ¹	(87,895)	(97,547)
Total gross deferred tax liabilities	(905,622)	(913,725)
Net deferred tax (liabilities) assets	\$ (378,337)	\$ (335,790)

¹ Other deferred tax assets and other deferred tax liabilities are primarily comprised of the deferred tax benefit and obligation associated with operating lease liabilities and the associated right of use assets, respectively.

In management's judgment, the net deferred tax assets in the preceding table are more likely than not to be realized based on the consideration of deferred tax liability reversals and future taxable income. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions that in the judgment of management at the present time are more likely than not to be unrealized. The valuation allowance increased \$8.3 million in 2025, related all to non-U.S. items. Subsequent reductions of the valuation allowance are expected to be reported as reductions of tax expense, assuming no offsetting change in the deferred tax asset.

The Company has a U.S. net operating loss carryforward of \$1.1 billion at year-end 2025 with a corresponding deferred tax asset of \$225.0 million. The Company believes the U.S. net operating loss being carried forward will more likely than not be utilized in future periods prior to expirations in 2037.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note H - Income Taxes (Continued)

Other Information

Currently, the Company considers \$100.0 million of Canada's past foreign earnings not permanently reinvested, with an accompanying \$5.0 million liability. At December 31, 2025, \$1.6 billion of past foreign earnings are considered permanently reinvested. The Company closely and routinely monitors these reinvestment positions considering underlying facts and circumstances pertinent to our business and the future operation of the Company.

Uncertain Income Tax Positions

The financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon ultimate settlement. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50% likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in "Other taxes payable" and "Deferred credits and other liabilities" in the Consolidated Balance Sheets for current and long-term portions, respectively. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the three years presented is shown in the following table.

<i>(Thousands of dollars)</i>	2025	2024	2023
Balance at January 1	\$ 9,979	\$ 6,384	\$ 3,928
Additions for tax positions related to current year	–	1,643	–
Additions for tax positions related to prior year	–	1,952	2,456
Reductions for tax positions related to prior year	(882)	–	–
Settlements with taxing authorities	(946)	–	–
Balance at December 31	<u>\$ 8,151</u>	<u>\$ 9,979</u>	<u>\$ 6,384</u>

All additions or settlements to the above liability affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities of \$0.3 million as of December 31, 2025, 2024 and 2023, respectively, for interest and penalties associated with uncertain tax positions. There were no interest or penalties associated with uncertain tax positions included in income tax expense for any period presented.

In 2026, the Company currently does not expect to add to the provision for uncertain tax positions. Although existing liabilities could be reduced by settlement with taxing authorities or due to statute of limitations closing, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statements of Operations during 2026.

The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. Additionally, the Company could be required to pay amounts into an escrow account as any matters are identified and appealed with the relevant taxing authorities. As of December 31, 2025, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States - 2016; Canada - 2021; and Malaysia - 2018. The Company has retained certain possible liabilities and rights to income tax receivables relating to Malaysia for the years prior to 2019.

Note I - Incentive Plans

Murphy utilizes cash-based and/or share-based incentive awards to supplement normal salaries as compensation for executive management and certain employees. For share-based awards that qualify for equity accounting, costs are recognized as an expense in the Consolidated Statements of Operations, using a grant date fair value-based measurement method, over the periods that the awards vest. For cash-settled equity awards that are required to be accounted for under liability accounting rules, costs are recognized as expense using a fair value-based measurement method over the vesting period, but expense is adjusted as necessary through the date the award value is finally determined. Total expense for liability awards is ultimately adjusted to the final intrinsic value for the award.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note I - Incentive Plans (Continued)

In May 2025, the Company's shareholders approved the 2025 Long-Term Incentive Plan (the 2025 Long-Term Plan) to replace the 2020 Long-Term Incentive Plan (the 2020 Long-Term Plan). All awards granted on or after May 14, 2025, will be made under the 2025 Long-Term Plan. Additional information on the 2025 Long-Term Plan can be found in the Company's Definitive Proxy Statement (Definitive 14A) dated March 28, 2025.

The Company currently has outstanding incentive awards issued to certain employees under the Annual Incentive Plan (AIP), the 2020 Long-Term Plan, and the 2025 Long-Term Plan.

The AIP authorizes the Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the AIP are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee.

The 2025 Long-Term Plan authorizes the Committee to make grants of the Company's common stock to employees. These grants may be in the form of stock options (nonqualified or incentive), Stock Appreciation Rights (SARs), restricted stock, RSUs, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2025 Long-Term Plan will expire in 2035 and authorizes the issuance of up to 3.885 million shares of common stock over its term. Shares issued pursuant to awards granted under this Plan may be shares that are authorized and unissued or shares that were reacquired by the Company, including shares purchased in the open market. Share awards that have been canceled, expired, forfeited or otherwise not issued under an award shall not count as shares issued under this Plan. Based on awards made to date, 3.872 million shares are available for grant under the 2025 Long-Term Plan at December 31, 2025.

The Company also has a stock plan that permits the issuance of RSUs, stock options, or a combination thereof, to non-employee directors (NEDs). The Company currently has outstanding incentive awards issued to directors under the 2021 Stock Plan for NEDs (2021 NED Plan) and the 2018 Stock Plan for NEDs. All awards on or after May 12, 2021, were made under the 2021 NED Plan.

The Company generally expects to issue treasury shares to satisfy the vesting of restricted stock and RSUs.

Amounts recognized in the financial statements with respect to share-based plans for each of the three years presented are shown in the following table.

<i>(Thousands of dollars)</i>	2025	2024	2023
Compensation charged against income before income tax benefit	\$ 50,107	\$ 40,831	\$ 58,760
Related income tax benefit recognized in income	6,438	5,513	9,330

As of December 31, 2025, there were \$46.5 million in compensation costs, to be expensed over approximately the next two years, related to unvested share-based compensation arrangements granted by the Company. Employees receive net shares, after applicable withholding obligations, upon each RSU vest.

Equity-Settled Awards

PERFORMANCE-BASED RESTRICTED STOCK UNITS - PSUs to be settled in common shares were granted in 2022, 2023, 2024 and February 2025 under the 2020 Long-Term Plan, and in August 2025 under the 2025 Long-Term Plan. Each grant will vest if the Company achieves specific performance objectives at the end of the designated performance period. Additional shares may be awarded if performance objectives are exceeded. If performance goals are not met, PSUs will not vest, but the recognized compensation cost associated with the stock award would not be reversed. The performance conditions for the PSUs are weighted 80% on the Company's total shareholder return (TSR) relative to an industry peer group and 20% on the return on average capital employed (ROACE), measured over the applicable performance period. ROACE is calculated by dividing the Company's EBITDA by the average of the opening and closing Capital Employed (the sum of total equity and short-term and long-term debt). During the performance period, PSUs are subject to transfer restrictions and are subject to forfeiture if a grantee terminates for reasons other than retirement, disability or death. Termination for these three reasons will lead to a pro rata award of amounts earned. No dividends are paid, nor do voting rights exist on awards of PSUs prior to their settlement.

The fair value of the PSUs based on the Company's TSR was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three-year performance measurement period. The risk-free interest

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note I - Incentive Plans (Continued)

rate is based on the yield curve of three-year U.S. Treasury bonds, and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2025, 2024 and 2023 are presented in the following table.

	2025	2024	2023
Fair value per share at grant date	\$19.65 - \$22.11	\$41.95	\$60.46
Assumptions			
Expected volatility	40.00%	50.00%	81.00%
Risk-free interest rate	4.25%	4.14%	3.90%
Stock beta	0.980	1.062	1.034
Expected life	3.0 years	3.0 years	3.0 years

The fair value of the PSUs based on ROACE was estimated based on the average high/low price of the Company's stock on the grant date.

Changes in PSUs outstanding for each of the last three years are presented in the following table.

<i>(Number of stock units)</i>	2025	2024	2023
Outstanding at beginning of year	1,392,421	1,818,188	2,148,467
Granted	657,730	536,900	409,160
Vested and issued	(481,670)	(938,599)	(408,135)
Forfeited	(104,966)	(24,068)	(331,304)
Outstanding at end of year	1,463,515	1,392,421	1,818,188

TIME-BASED RESTRICTED STOCK UNITS - Time-based RSUs have been granted to the Company's non-employee directors under the 2021 NED Plan, and to certain employees under the 2020 Long-Term Plan and 2025 Long-Term Plan.

The fair value of the time-based RSUs awarded for each of the last three years is presented in the following table.

Type of Plan	Valuation Methodology	2025	2024	2023
Non-Employee Directors ¹	Closing Stock Price at Grant Date	\$22.50 - \$31.25	\$30.26 - \$45.70	\$43.27
Long-Term Incentive Plan ²	Average High/Low Stock Price at Grant Date	\$23.09 - \$25.98	\$37.78 - \$45.98	\$42.20

¹ Under the 2021 NED Plan, RSUs granted in 2025 are scheduled to vest in February 2026.

² The RSUs granted under the 2020 Long-Term Plan and the 2025 Long-Term Plan generally vest on the third anniversary of the date of grant.

Changes in RSUs outstanding for each of the last three years are presented in the following table.

<i>(Number of share units)</i>	2025	2024	2023
Outstanding at beginning of year	1,558,600	1,219,584	1,227,792
Granted	559,284	741,228	556,100
Vested and issued	(360,281)	(330,444)	(517,047)
Forfeited	(95,951)	(71,768)	(47,261)
Outstanding at end of year	1,661,652	1,558,600	1,219,584

STOCK OPTIONS - In 2017, the Company ceased the inclusion of stock options and SARs as a part of the long-term incentive compensation mix. As of December 31, 2024, there were no outstanding SARs or stock options.

During 2023, 11,000 stock options were exercised, and 2,000 stock options were forfeited, both at an exercise price of \$28.51 per share, leaving zero options outstanding as of December 31, 2023.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note I - Incentive Plans (Continued)

Cash-Settled Awards

The Company has granted phantom stock-based incentive awards to be settled in cash to certain employees in the form of CRSUs.

CRSUs generally settle on the third anniversary of the date of grant. Each award granted is settled, net of applicable income tax withholdings, in cash rather than with common shares. Total pretax expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was \$7.5 million in 2025, \$1.7 million in 2024 and \$29.4 million in 2023.

The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and certain other employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of \$37.8 million, \$37.1 million and \$30.9 million was recorded in 2025, 2024 and 2023, respectively, for these plans.

Note J - Employee and Retiree Benefit Plans

PENSION AND OTHER POSTRETIREMENT PLANS - The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors' plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors other postretirement benefits such as health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

Upon the disposal of Murphy's former U.K. refining and marketing assets, the Company retained all vested defined benefit pension obligations associated with former employees of this business. No additional benefits will accrue to these former U.K. employees under the Company's retirement plan after the date of their separation from Murphy.

GAAP requires the Company to recognize the overfunded or underfunded status of its defined benefit plans as an asset or liability in its Consolidated Balance Sheets and to recognize changes in that funded status between periods through "Accumulated other comprehensive loss".

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations, fair value of assets and funded status for the respective periods presented.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued
Note J - Employee and Retiree Benefit Plans (Continued)

	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
<i>(Thousands of dollars)</i>				
Change in benefit obligation				
Obligation at January 1	\$ 655,324	\$ 699,151	\$ 54,994	\$ 63,808
Service cost	7,094	7,042	382	436
Interest cost	33,798	33,554	3,261	2,923
Participant contributions	—	—	2,762	2,730
Actuarial (gain) loss ¹	1,175	(35,417)	17,681	825
Medicare Part D subsidy	—	—	383	358
Exchange rate changes	8,010	(3,263)	9	(14)
Benefits paid	(45,907)	(45,743)	(16,073)	(16,072)
Obligation at December 31	<u>659,494</u>	<u>655,324</u>	<u>63,399</u>	<u>54,994</u>
Change in plan assets				
Fair value of plan assets at January 1	492,120	477,809	—	—
Actual return on plan assets	48,285	27,317	—	—
Employer contributions	25,067	35,477	12,928	12,984
Participant contributions	—	—	2,762	2,730
Medicare Part D subsidy	—	—	383	358
Exchange rate changes	7,514	(2,740)	—	—
Benefits paid	(45,907)	(45,743)	(16,073)	(16,072)
Fair value of plan assets at December 31	<u>527,079</u>	<u>492,120</u>	<u>—</u>	<u>—</u>
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	14,925	1,819	—	—
Other accrued liabilities	(10,354)	(10,617)	(4,663)	(4,237)
Deferred credits and other liabilities	<u>(136,986)</u>	<u>(154,406)</u>	<u>(58,736)</u>	<u>(50,757)</u>
Fund Status and net plan liability recognized at December 31	<u>\$ (132,415)</u>	<u>\$ (163,204)</u>	<u>\$ (63,399)</u>	<u>\$ (54,994)</u>

¹ Actuarial losses in 2025 for other post retirement benefits primarily relate to trend rate increases for incurred claims. Actuarial gains for pension benefits in 2024 primarily relate to the increase in the discount rate assumption, which decreases the pension benefit obligation.

At December 31, 2025, amounts included in "Accumulated other comprehensive loss" in the Consolidated Balance Sheets, before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

	Pension Benefits	Other Postretirement Benefits
<i>(Thousands of dollars)</i>		
Net actuarial gain (loss)	\$ (148,280)	\$ 18,862
Prior service (credit) cost	(16,320)	2,873
	<u>\$ (164,600)</u>	<u>\$ 21,735</u>

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note J - Employee and Retiree Benefit Plans (Continued)

The table that follows includes projected benefit obligations, accumulated benefit obligations and fair value of plan assets for plans where the accumulated benefit obligation exceeded the fair value of plan assets.

<i>(Thousands of dollars)</i>	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
	2025	2024	2025	2024	2025	2024
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	\$ –	\$ 497,947	\$ –	\$ 489,225	\$ –	\$ 477,983
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	147,339	145,058	145,545	143,859	–	–
Unfunded other postretirement plans	63,399	54,994	63,399	54,994	–	–

The table that follows provides the components of net periodic benefit expense for each of the three years presented.

<i>(Thousands of dollars)</i>	Pension Benefits			Other Postretirement Benefits		
	2025	2024	2023	2025	2024	2023
Service cost	\$ 7,094	\$ 7,042	\$ 6,542	\$ 382	\$ 436	\$ 495
Interest cost	33,798	33,554	34,140	3,261	2,923	3,241
Expected return on plan assets	(35,511)	(33,427)	(32,839)	–	–	–
Amortization of prior service cost (credit)	1,967	2,316	620	(532)	(532)	(532)
Recognized actuarial (gain) loss	7,262	9,438	9,776	(3,182)	(3,586)	(3,512)
Net periodic benefit cost (credit)	14,610	18,923	18,239	(71)	(759)	(308)
Other pension costs	276	251	219	–	–	–
Total net periodic benefit cost (credit)	\$ 14,886	\$ 19,174	\$ 18,458	\$ (71)	\$ (759)	\$ (308)

The preceding tables in this note include the following amounts related to foreign benefit plans.

<i>(Thousands of dollars)</i>	Pension Benefits		Other Postretirement Benefits	
	2025	2024	2025	2024
Benefit obligation at December 31	\$ 109,883	\$ 115,428	\$ 90	\$ 106
Fair value of plan assets at December 31	110,280	103,445	–	–
Net plan liabilities recognized	397	(11,983)	(90)	(106)
Net periodic benefit (credit) expense	2,131	1,480	(35)	(44)

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note J - Employee and Retiree Benefit Plans (Continued)

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2025 and 2024 and net periodic benefit expense for 2025 and 2024.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2025	2024	2025	2024	2025	2024	2025	2024
Discount rate on obligation, interest cost and service cost	5.41 %	5.58 %	5.48 %	5.65 %	5.54 %	5.17 %	5.66 %	5.15 %
Rate of compensation increase	3.50 %	3.38 %	—	—	3.50 %	3.50 %	—	—
Cash balance interest credit rate	3.70 %	3.20 %	—	—	—	—	—	—
Expected return on plan assets	—	—	—	—	7.29 %	7.19 %	—	—

The discount rates used for determining the plan obligations and expense are based on high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate, which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company. The plan's cash balance interest accumulation rate is the greater of the annual yield on 10-year treasury constant maturities or 1.89%.

Benefit payments, reflecting expected future service as appropriate, which are expected to be paid in future years from the assets of the plans or by the Company, are shown in the following table.

<i>(Thousands of dollars)</i>	Pension Benefits	Other Postretirement Benefits
2026	\$ 49,819	\$ 4,663
2027	51,276	4,710
2028	51,786	4,872
2029	51,646	4,772
2030	53,230	4,752
2031-2035	260,581	23,671

For purposes of measuring postretirement benefit obligations at December 31, 2025, the future annual rates of increase in the cost of health care were assumed to be 7.9% for 2026 decreasing each year to an ultimate rate of 4.0% in 2050 and thereafter.

During 2025, the Company made contributions of \$24.3 million to its domestic defined benefit pension plans and \$12.9 million to its domestic postretirement benefits plan. During 2026, the Company currently expects to make contributions of \$23.8 million to its domestic defined benefit pension plans, \$0.8 million to its foreign defined benefit pension plans and \$4.7 million to its domestic postretirement benefits plan.

PLAN INVESTMENTS - Murphy Oil Corporation maintains an Investment Policy Statement that establishes investment standards related to its funded domestic qualified retirement plan. Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include equities, fixed income and other investments, including hedge funds, real estate and cash equivalent securities. Investment managers are prohibited from investing in equity or fixed income securities issued by the Company. The majority of plan assets are highly liquid, providing flexibility for benefit payment requirements. The current target allocations for plan assets are 40-75% equity securities, 20-60% fixed

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note J - Employee and Retiree Benefit Plans (Continued)

income securities, 0-15% alternatives and 0-20% cash and equivalents. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

The weighted average asset allocation for the Company's funded pension benefit plans at the respective balance sheet dates are shown in the following table.

	December 31,	
	2025	2024
Equity securities	45.2 %	57.3 %
Fixed income securities	42.7 %	36.2 %
Alternatives	7.4 %	3.7 %
Cash equivalents	4.7 %	2.8 %
	<u>100.0 %</u>	<u>100.0 %</u>

The Company's weighted average expected return on plan assets was 7.3% in 2025 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 7.3% expected return was comprised of the weighted average expected future equity securities return of 7.6% and a fixed income securities return of 5.0%. An average expected investment expense of 0.5% is included in this calculation. Over the last 10 years, the return on funded retirement plan assets has averaged 4.1%.

At December 31, 2025, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
	Fair Value at December 31, 2025	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<i>(Thousands of dollars)</i>				
Domestic Plans				
Equity securities:				
U.S. core equity	\$ 83,956	\$ 73,999	\$ —	\$ 9,957
U.S. small/midcap	56,699	56,699	—	—
Other alternative strategies	21,032	—	—	21,032
International equity	27,772	27,772	—	—
Emerging market equity	13,518	13,518	—	—
Fixed income securities:				
U.S. fixed income	186,995	119,205	67,790	—
International commingled trust fund	7,047	—	7,047	—
Cash and equivalents	19,779	19,779	—	—
Total Domestic Plans	<u>416,798</u>	<u>310,972</u>	<u>74,837</u>	<u>30,989</u>
Foreign Plans				
Equity securities funds	13,946	—	13,946	—
Fixed income securities funds	30,986	—	30,986	—
Diversified pooled fund	42,124	—	42,124	—
Other	18,454	—	532	17,922
Cash and equivalents	4,771	—	4,771	—
Total Foreign Plans	<u>110,281</u>	<u>—</u>	<u>92,359</u>	<u>17,922</u>
Total	<u>\$ 527,079</u>	<u>\$ 310,972</u>	<u>\$ 167,196</u>	<u>\$ 48,911</u>

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note J - Employee and Retiree Benefit Plans (Continued)

At December 31, 2024, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
	Fair Value at December 31, 2024	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
<i>(Thousands of dollars)</i>				
Domestic Plans				
Equity securities:				
U.S. core equity	\$ 87,124	\$ 87,124	\$ —	\$ —
U.S. small/midcap	51,978	51,978	—	—
Other alternative strategies	965	—	—	965
International equity	22,724	22,724	—	—
Emerging market equity	7,638	7,638	—	—
Fixed income securities:				
U.S. fixed income	208,755	105,302	103,453	—
Cash and equivalents	9,491	9,491	—	—
Total Domestic Plans	388,675	284,256	103,453	965
Foreign Plans				
Equity securities funds	14,377	—	14,377	—
Fixed income securities funds	26,500	—	26,500	—
Diversified pooled fund	41,054	—	41,054	—
Other	17,049	—	—	17,049
Cash and equivalents	4,465	—	4,465	—
Total Foreign Plans	103,445	—	86,396	17,049
Total	\$ 492,120	\$ 284,256	\$ 189,849	\$ 18,014

The definition of levels within the fair value hierarchy in the tables above is included in [Note Q](#).

For domestic plans, U.S. core, small/midcap, international, emerging market equity securities and U.S. treasury securities are valued based on quoted prices in active markets. For commercial paper securities, the prices received generally utilize observable inputs in the pricing methodologies. Other alternative strategies funds consist of four investments. The Company's domestic level 3 investments primarily relate to funds which invest primarily in U.S. middle-market companies using various types of credit instruments.

For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. and Canadian securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of U.K. and foreign equity securities.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note J - Employee and Retiree Benefit Plans (Continued)

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

	Hedged Funds and Other Alternative Strategies
<i>(Thousands of dollars)</i>	
Total at December 31, 2023	\$ 24,454
Actual return (loss) on plan assets ¹ :	
Relating to assets held at the reporting date	(3,574)
Purchases, sales and settlements	(2,865)
Total at December 31, 2024	18,015
Actual return on plan assets ¹ :	
Relating to assets held at the reporting date	2,394
Purchases, sales and settlements	28,502
Total at December 31, 2025	\$ 48,911

¹ Gains and losses on Level 3 plan assets are recognized in the Consolidated Statements of Comprehensive Income (Loss) under the caption "Retirement and postretirement benefit plans."

401(K) PLANS - Most full-time U.S. employees of the Company may participate in a 401(k) or similar savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's plan, with a maximum match of 6.0%. Amounts charged to expense for the Company's match to these plans were \$9.1 million in 2025, \$8.7 million in 2024 and \$8.5 million in 2023.

Note K - Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS - Murphy uses derivative instruments, such as swaps and zero-cost commodity price collar contracts, to manage certain risks related to commodity prices, foreign currency exchange rates and interest rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company's senior management. The Company does not hold any derivatives for speculative purposes, and it does not use derivatives with leveraged or complex features. Derivative instruments are traded with creditworthy major financial institutions or over national exchanges, such as the NYMEX. The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Operations.

Commodity Price Risks

The Company is subject to commodity price risk related to products it produces and sells. During 2025 and 2024 the Company entered into natural gas swap contracts. Under the swap contracts, which mature monthly, the Company pays the average monthly price in effect and receives the fixed contract price on a notional amount of sales volume, thereby fixing the price for the commodity sold.

During 2025, the Company entered into natural gas swap contracts that matured by December 31, 2025. The Company did not have any outstanding natural gas derivative contracts at year end. Volumes per day and the weighted average prices for these contracts were as follows:

NYMEX Henry Hub	Area	Commodity	Volumes MMCF/d	Price/MCF	Start Date	End Date
Fixed price derivative swap	United States	Natural gas	40	\$ 3.58	2/1/2025	6/30/2025
Fixed price derivative swap	United States	Natural gas	60	\$ 3.65	7/1/2025	9/30/2025
Fixed price derivative swap	United States	Natural gas	60	\$ 3.74	10/1/2025	12/31/2025

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note K - Financial Instruments and Risk Management (Continued)

During 2024, the Company entered into natural gas swap contracts that were effective in 2025. At December 31, 2024, volumes per day associated with outstanding natural gas derivative contracts and the weighted average prices for these contracts were as follows:

NYMEX Henry Hub	Area	Commodity	Volumes MMCF/d	Price/MCF	Start Date	End Date
Fixed price derivative swap	United States	Natural gas	20	\$ 3.20	1/1/2025	1/31/2025

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. The Company had no foreign currency exchange short-term derivative instruments outstanding as of December 31, 2025 and 2024.

At December 31, 2025 and 2024, the fair value of derivative instruments not designated as hedging instruments are presented in the following table. See also [Note O](#).

<i>(Thousands of dollars)</i>		Asset (Liability) Derivatives Fair Value at December 31,		
Type of Derivative Contract	Balance Sheets Location	2025	2024	
Commodity swaps	Accounts payable	\$ –	(1,707)	

The gains and losses recognized in the Consolidated Statements of Operations for derivative instruments not designated as hedging instruments for each of the three years presented are shown in the following table.

<i>(Thousands of dollars)</i>		Gain (Loss)		
		Year Ended December 31,		
Type of Derivative Contract	Statements of Operations Locations	2025	2024	2023
Commodity swaps	Gain (loss) on derivative instruments	\$ 5,927	\$ (1,707)	\$ –

Credit Risks

The Company is subject to credit risks primarily associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of oil and natural gas in the U.S. and Canada and cost sharing amounts, of operating and capital costs billed to partners, for properties operated by Murphy. The credit history and financial condition of potential customers are reviewed before credit is extended. Security is obtained when deemed appropriate based on a potential customer's financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk associated with any one customer. Cash balances and cash equivalents are held with several major financial institutions, which limit the Company's exposure to credit risk for its cash assets. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal, because counterparties to the majority of transactions are major financial institutions.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note L - Net Income (Loss) Per Common Share

Net income attributable to Murphy was used as the numerator in computing both basic and diluted income per common share for each of the three years presented. The following table reconciles the weighted-average shares outstanding used for these computations.

<i>(Weighted-average shares, except per share amounts)</i>	2025	2024	2023
Basic method	143,124,118	150,011,458	155,233,560
Dilutive restricted stock units	901,204	1,015,894	1,412,869
Diluted method	144,025,322	151,027,352	156,646,429

NET INCOME (LOSS) PER COMMON SHARE - BASIC

Continuing operations	\$ 0.73	\$ 2.73	\$ 4.27
Discontinued operations	—	(0.02)	(0.01)
Net income	\$ 0.73	\$ 2.71	\$ 4.26

NET INCOME (LOSS) PER COMMON SHARE - DILUTED

Continuing operations	\$ 0.72	\$ 2.72	\$ 4.23
Discontinued operations	—	(0.02)	(0.01)
Net income	\$ 0.72	\$ 2.70	\$ 4.22

Note M - Other Financial Information

Gain (Loss) from Foreign Currency Transactions

Net gains (losses) from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Operations were \$29.4 million loss in 2025, \$45.4 million gain in 2024 and \$10.8 million loss in 2023.

Supplemental Information to Statements of Cash Flows

<i>(Thousands of dollars)</i>	2025	2024	2023
Net (increase) decrease in operating working capital, excluding cash and cash equivalents:			
(Increase) decrease in accounts receivable	\$ (75,437)	\$ 71,081	\$ 47,151
(Increase) decrease in inventories	(1,461)	1,327	329
(Increase) decrease in prepaid expenses	539	1,192	(1,293)
Increase (decrease) in accounts payable and accrued liabilities ¹	3,101	3,287	(140,011)
Increase (decrease) in income taxes payable	(794)	(2,004)	(5,537)
Net (increase) decrease in noncash working capital	\$ (74,052)	\$ 74,883	\$ (99,361)

Supplementary disclosures:

Interest paid, net of amounts capitalized of \$8.8 million in 2025, \$11.4 million in 2024 and \$14.5 million in 2023	88,119	78,806	108,912
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Non-cash investing activities:

Asset retirement costs capitalized	\$ 9,629	\$ 47,233	\$ 32,975
(Increase) decrease in capital expenditure accrual	(98,778)	(5,935)	17,517

¹ Excludes receivable/payable balances relating to mark-to-market of derivative instruments.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note N - Accumulated Other Comprehensive Loss

The components of "Accumulated other comprehensive loss" on the Consolidated Balance Sheets for the periods presented and the changes during the respective periods are shown net of taxes in the following table.

<i>(Thousands of dollars)</i>	Foreign Currency Translation Gains (Losses)	Retirement and Postretirement Benefit Plan Adjustments	Total
Balance at December 31, 2023	\$ (381,632)	\$ (139,485)	\$ (521,117)
2024 components of other comprehensive income (loss):			
Before reclassifications to income	(134,692)	23,713	(110,979)
Reclassifications to income	—	4,024 ¹	4,024
Net other comprehensive income	(134,692)	27,737	(106,955)
Balance at December 31, 2024	(516,324)	(111,748)	(628,072)
2025 components of other comprehensive income (loss):			
Before reclassifications to income	73,993	(3,633)	70,360
Reclassifications to income	—	3,485 ¹	3,485
Net other comprehensive income (loss)	73,993	(148)	73,845
Balance at December 31, 2025	\$ (442,331)	\$ (111,896)	\$ (554,227)

¹ Reclassifications before taxes of \$4.2 million and \$5.4 million are included in the computation of net periodic benefit expense in 2025 and 2024, respectively. See [Note J](#) for additional information. Related income taxes of \$0.7 million and \$1.4 million are included in income tax expense in 2025 and 2024, respectively.

Note O - Assets and Liabilities Measured at Fair Value

Fair Values - Recurring

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. The fair value hierarchy is based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. 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. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The fair value measurements for these assets and liabilities for the respective periods presented are shown in the following table.

<i>(Thousands of dollars)</i>	December 31, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Liabilities:								
Nonqualified employee savings plan	\$ 22,205	\$ —	\$ —	\$ 22,205	\$ 19,469	\$ —	\$ —	\$ 19,469
Commodity swaps	—	—	—	—	—	1,707	—	1,707
	<u>\$ 22,205</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 22,205</u>	<u>\$ 19,469</u>	<u>\$ 1,707</u>	<u>\$ —</u>	<u>\$ 21,176</u>

The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in "Selling and general expenses" in the Consolidated Statements of Operations.

As of December 31, 2025, there were no outstanding commodity (NYMEX Henry Hub natural gas) swaps subject to fair value measurement. The liabilities associated with these contacts have been finalized as of December 31, 2025 and were based on realized NYMEX Henry Hub pricing. The commodity swaps liability as of December 31, 2024 was \$1.7 million and recorded as "Accounts payable" in the Consolidated Balance Sheets. The fair value of

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note O - Assets and Liabilities Measured at Fair Value (Continued)

the commodity swaps was based on active market quotes for NYMEX Henry Hub natural gas. The before tax income effect of changes in fair value of natural gas derivative contracts was recorded in "Gain (loss) on derivative instruments" in the Consolidated Statements of Operations.

The Company was previously exposed to contingent consideration payments related to a prior asset purchase agreement, which required additional payments contingent on specified revenue thresholds and project milestones being met. At December 31, 2022, the Company's liabilities were finalized and no longer subject to fair value measurement. Final cash payment was made in 2023 and was recorded to "Contingent consideration payment" in the Consolidated Statements of Cash Flows.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at December 31, 2025 and 2024.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2025 and 2024. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. Substantially all of the Company's long-term debt is actively traded in open markets, and accordingly, is classified as Level 1 in the fair value hierarchy. The Company has off-balance sheet exposures relating to certain letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was minimal.

	December 31,			
	2025		2024	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<i>(Thousands of dollars)</i>				
Financial liabilities:				
Current and long-term debt	\$ 1,385,080	\$ 1,326,101	\$ 1,275,374	\$ 1,185,961

Fair Values - Nonrecurring

Impairment expenses of \$115.0 million and \$62.9 million were incurred in 2025 and 2024, respectively. In 2025, an impairment charge of \$115.0 million (\$92.0 million excluding NCI) was recorded for the Dalmatian field, in the Gulf of America, as certain projects in the field were less competitive for capital allocation. In 2024, an impairment charge of \$34.5 million was recorded for the Calliope field and an impairment charge of \$28.4 million was recorded for the Nearly Headless Nick field, in the Gulf of America. Both impairment charges were due to operational issues that led to reserve reductions.

The fair values were determined by internal discounted cash flow models using estimates of future production, prices, costs and discount rates believed to be consistent with those used by principal market participants in the applicable region.

The fair value information associated with the impaired properties is presented in the following tables.

	Year Ended December 31, 2025				
	Fair Value			Net Book Value Prior to Impairment	Total Pretax Impairment
	Level 1	Level 2	Level 3		
<i>(Thousands of dollars)</i>					
Assets:					
Impaired proved properties					
United States - Offshore	\$ -	\$ -	\$ 42,397	\$ 157,399	\$ 115,002

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note O - Assets and Liabilities Measured at Fair Value (Continued)

	Year Ended December 31, 2024						
	Fair Value			Net Book Value Prior to Impairment		Total Pretax Impairment	
(Thousands of dollars)	Level 1	Level 2	Level 3				
Assets:							
Impaired proved properties							
United States - Offshore	\$	–	\$	–	\$	501	\$ 63,410
							\$ 62,909

Note P - Commitments

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Canada Onshore. The U.S. Onshore and U.S. Offshore transportation contracts require minimum monthly payments through 2045, while the Canada Onshore transportation contracts call for minimum monthly payments through 2051. In the U.S. and Canada Onshore, future required minimum annual payments for the next five years are \$132.8 million in 2026, \$107.3 million in 2027, \$97.6 million in 2028, \$66.3 million in 2029 and \$45.8 million in 2030. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement.

Commitments for Vietnam in Other Offshore include future operating agreements for production activities. Annual payments for the next five years are \$23.6 million in 2026, \$23.1 million in 2027, \$24.0 million in 2028, \$23.9 million in 2029 and \$24.2 million in 2030.

Commitments for capital expenditures were approximately \$551.2 million at December 31, 2025, primarily consisting of \$245.3 million for the Gulf of America, \$82.6 million for the Eagle Ford Shale, \$49.8 million for Canada, \$127.5 million for Vietnam, and \$45.0 million in for Côte d'Ivoire.

Note Q - Environmental and Other Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax legislation changes, including tax rate changes, and retroactive tax claims; trade policies, tariffs and other trade restrictions; royalty and revenue sharing increases; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and natural gas or mineral leases; restrictions on drilling and/or production; laws, regulations and government action intended for the promotion of safety and the protection and/or remediation of the environment including in connection with the purported causes or potential impacts of climate change; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Given the factors involved in various government actions, including political considerations, it is difficult to predict their likelihood, the form they may take, or the effect they may have on the Company.

ENVIRONMENTAL MATTERS - Murphy and other companies in the oil and natural gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment and protection of health and safety. The principal environmental, health and safety laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials; the emission and discharge of such materials to the environment, including methane and other GHG emissions; wildlife, habitat and water protection; water access, use and disposal; the placement, operation and decommissioning of production equipment; the health and safety of our employees, contractors and communities where our operations are located, including indigenous communities; and the causes and impacts of climate change. These laws and regulations also generally require permits for existing operations, as well as the construction or development of new operations and the decommissioning of facilities once production has ceased.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note Q - Environmental and Other Contingencies (Continued)

Violation of federal or state environmental, health and safety laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not adequately insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result. In addition, Item 103 of SEC Regulation S-K requires disclosure of certain environmental matters when a governmental authority is a party to the proceedings and such proceedings involve potential monetary sanctions that the Company reasonably believes will exceed a specified threshold. Pursuant to SEC amendments to this item, the Company will be using a threshold of \$1.0 million for such proceedings and the Company is not aware of environmental legal proceedings likely to exceed this \$1.0 million threshold.

In recent years, there has been an increase in regulatory oversight of the oil and gas industry at the state and federal level, with a focus on climate change and GHG emissions (including methane emissions). For example, in March 2024, the EPA published its final rule regulating methane and volatile organic compounds emissions in the oil and gas industry which, among other things, requires periodic inspections to detect leaks (and subsequent repairs), places stringent restrictions on venting and flaring of methane, and establishes a program whereby third parties can monitor and report large methane emissions to the EPA. However, the EPA has since published a final rule extending several compliance deadlines associated with the new methane rules. In November 2024, the EPA published its final rule implementing a charge on large emitters of waste methane from the oil and gas sector. This rule, however, was disapproved by a joint Congressional resolution in March 2025, and the OBBBA passed in July 2025 extended the imposition of the waste emission charge until 2034. In addition, an international climate agreement (the Paris Agreement) was agreed to at the 2015 United Nations Framework Convention on Climate Change in Paris, France. In January 2025, the United States submitted formal notification to the United Nations that it intends to withdraw from the Paris Agreement. Pursuant to the terms of the Paris Agreement, the withdrawal came into effect on January 27, 2026. In September 2025, the EPA announced a proposal to end the GHGRP for all sectors except petroleum and natural gas systems (excluding reporting for natural gas distribution, which would also be eliminated under the proposal). Reporting for petroleum and natural gas systems under the GHGRP would be deferred until 2034 under the proposal. On January 7, 2026, the Trump Administration issued an executive order directing United States executive agencies to cease participation in and withdraw from the United Nations Framework Convention on Climate Change. On February 12, 2026, the EPA announced the repeal of its 2009 "Endangerment Finding" under the Clean Air Act, which found that GHGs endanger the public health and welfare of current and future generations and emissions of GHGs from motor vehicles contribute to GHG pollution. The repeal calls into question the EPA's authority to regulate GHGs, as well as the EPA's prior scientific assessment of climate change risks. Litigation regarding the repeal is anticipated and it is unclear how the repeal will impact the EPA's regulation of GHG emissions going forward. While presidential administrations may modify, revise or repeal rules related to climate change and GHG emissions, the general trend has been towards stricter regulation over time. Further, many states have adopted or are considering regulations related to GHG emissions.

The Company currently owns or leases and has in the past owned or leased properties at which hazardous substances have been or are being handled. Hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws, the Company could be required to investigate, remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to investigate and clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup, and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. Murphy USA Inc. has retained any environmental exposure associated with Murphy's former U.S. marketing operations that were spun-off in August 2013. The Company believes costs related to these sites will not have a material adverse effect on Murphy's net income, financial condition or liquidity in a future period. Depending on the evolution of laws, regulations and litigation outcomes relating to climate change, there can be no guarantee that climate change

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note Q - Environmental and Other Contingencies (Continued)

litigation will not in the future materially adversely affect our results of operations, cash flows and financial condition.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and additional expenditures could be required at known sites. However, based on information currently available to the Company, the amount of future investigation and remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on the Company's future net income, cash flows or liquidity.

LEGAL MATTERS – Murphy and its subsidiaries are engaged in a number of other legal proceedings (including litigation related to climate change), all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company's net income, financial condition or liquidity in a future period.

Note R - Common Stock Issued and Outstanding

Activity in the number of shares of common stock issued and outstanding for each of the three years presented is shown below.

<i>(Number of shares outstanding)</i>	2025	2024	2023
Beginning of year	145,845,124	152,748,642	155,467,319
Stock options exercised ¹	–	–	2,657
Restricted stock awards ¹	553,478	1,105,268	689,824
Treasury shares purchased	(3,613,450)	(8,008,786)	(3,411,158)
End of year	142,785,152	145,845,124	152,748,642

¹ Shares issued upon exercise of stock options and award of restricted stock are less than the amount reflected in [Note I](#) due to withholdings for statutory income taxes owed upon issuance of shares.

The Company's Board of Directors has authorized a share repurchase program whereby the Company can repurchase up to \$1,100.0 million of its common stock. This repurchase program has no time limit and may be suspended or discontinued completely at any time without prior notice as determined by the Company at its discretion and dependent upon a variety of factors.

During the year ended December 31, 2025, the Company repurchased 3.6 million shares of its common stock under the share repurchase program for \$100.0 million (\$100.8 million including excise taxes and fees). As of December 31, 2025, the Company had \$550.1 million of its common stock remaining available to repurchase under the program.

The share repurchase program is a component of the Company's capital allocation framework, the details of which can be found as part of the Company's [Form 8-K](#) filed on August 4, 2022 and [Form 8-K](#) filed on August 8, 2024.

Note S - Business Segments

Murphy's reportable segments are organized into geographic areas of operations. The Company's E&P activity is subdivided into segments for the U.S., Canada and all other countries. Each of these segments derive revenues primarily from the sale of crude oil, NGLs and/or natural gas. The Company's management team and Chief Operating Decision Maker (CODM) evaluates segment performance based on income (loss) from operations, excluding interest income and interest expense, and allocates financial and capital resources for each segment predominantly in the annual budget and forecasting process. The CODM also considers budget-to-actual variances on a monthly basis for the performance measure when making decisions about allocating capital and personnel to the segments. Murphy's President and Chief Executive Officer, Eric M. Hambly, acts as the CODM.

Customers that accounted for 10% or more of the Company's sales revenue for each of the below three years ended December 31, are shown below.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S - Business Segments (Continued)

	2025	2024	2023
Chevron Corporation	19 %	13 %	16 %
ExxonMobil Corporation	12 %	20 %	27 %
Phillips 66	N/A	10 %	N/A

Due to the quantity of active oil and natural gas purchasers in the markets where it produces hydrocarbons, the Company does not foresee any difficulty with selling its hydrocarbon production at fair market prices.

No assets were held for sale as of December 31, 2025 and 2024. The Company has accounted for its former U.K., Malaysia and U.S. refining and marketing operations as discontinued operations for all periods presented.

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. Corporate includes interest income, other gains and losses, interest expense and unallocated overhead and is shown in the tables to reconcile the business segments to consolidated totals.

"Other segment costs (income)" below are those items that are included in Segment income (loss) but are not regularly provided to the CODM or are reported to the CODM but are not considered to be significant segment expenses. "Other segment costs (income)" for the years presented included certain pension amortization costs allocated to the reportable segments, and dividend income from short-term investment accounts attributed to the Canada segment.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S - Business Segments (Continued)

	Exploration and Production				Corporate, and Discontinued Operations	Consolidated Total
(Millions of dollars)	United States ¹	Canada	Other	Total E&P		
Year ended December 31, 2025						
Revenue from production	\$ 2,153.9	\$ 530.2	\$ 5.7	\$ 2,689.8	\$ –	\$ 2,689.8
Gain on sales of assets and other operating income	5.9	1.7	10.0	17.6	13.8	31.4
Total revenues and other income	2,159.8	531.9	15.7	2,707.4	13.8	2,721.2
Lease operating expenses						
Lease operating expenses and taxes other than income	391.4	178.9	2.5	572.8	–	572.8
Repair and maintenance	60.8	5.1	–	65.9	–	65.9
Workovers	124.9	1.6	–	126.5	–	126.5
Total lease operating expenses	577.1	185.6	2.5	765.2	–	765.2
Severance and ad valorem taxes	37.7	1.5	–	39.2	–	39.2
Transportation, gathering and processing	107.0	92.7	–	199.7	–	199.7
Selling and general expenses	13.7	23.7	8.8	46.2	91.1	137.3
Exploration expenses						
Geological and geophysical	27.2	0.1	8.7	36.0	–	36.0
Dry holes and previously suspended exploration costs	(0.9)	–	31.0	30.1	–	30.1
Other exploratory costs, including undeveloped lease amortization and delay lease rentals	14.7	0.3	30.6	45.6	–	45.6
Total exploration expenses	41.0	0.4	70.3	111.7	–	111.7
Depreciation, depletion and amortization	822.1	144.8	2.5	969.4	8.4	977.8
Impairment of assets	115.0	–	–	115.0	–	115.0
Accretion of asset retirement obligations	46.6	10.3	0.7	57.6	0.1	57.7
Other operating expenses (income)	10.8	1.8	(0.9)	11.7	2.2	13.9
Interest income	(1.7)	–	–	(1.7)	(11.8)	(13.5)
Interest expense, net of capitalization	0.1	0.1	0.2	0.4	95.7	96.1
Income tax expense (benefit)						
Current income tax expense (benefit)	0.8	10.6	0.3	11.7	(1.8)	9.9
Deferred income tax expense (benefit)	76.9	4.0	(2.4)	78.5	(43.8)	34.7
Total income tax expense (benefit)	77.7	14.6	(2.1)	90.2	(45.6)	44.6
Other segment costs	4.2	1.6	0.3	6.1	31.6	37.7
Segment income (loss) - including NCI ¹	\$ 308.5	\$ 54.8	\$ (66.6)	\$ 296.7	\$ (157.9)	\$ 138.8
Additions to property, plant, equipment	\$ 763.5	\$ 152.5	\$ 180.9	\$ 1,096.9	\$ 21.2	\$ 1,118.1
Total assets at year-end	6,771.3	2,000.0	598.1	9,369.4	463.2	9,832.6

¹ Includes results attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S - Business Segments (Continued)

	Exploration and Production				Corporate, and Discontinued Operations	Consolidated Total
(Millions of dollars)	United States ¹	Canada	Other	Total E&P		
Year ended December 31, 2024						
Revenue from production	\$ 2,503.8	\$ 504.5	\$ 6.6	\$ 3,014.9	\$ –	\$ 3,014.9
Sales of purchased natural gas	–	3.7	–	3.7	–	3.7
Gain on sales of assets and other operating income	4.5	1.5	–	6.0	3.9	9.9
Total revenues and other income	<u>2,508.3</u>	<u>509.7</u>	<u>6.6</u>	<u>3,024.6</u>	<u>3.9</u>	<u>3,028.5</u>
Lease operating expenses						
Lease operating expenses and taxes other than income	471.3	176.8	1.6	649.7	–	649.7
Repair and maintenance	63.7	4.8	–	68.5	–	68.5
Workovers	214.9	3.9	–	218.8	–	218.8
Total lease operating expenses	<u>749.9</u>	<u>185.5</u>	<u>1.6</u>	<u>937.0</u>	<u>–</u>	<u>937.0</u>
Severance and ad valorem taxes	37.8	1.4	–	39.2	–	39.2
Transportation, gathering and processing	130.9	79.9	–	210.8	–	210.8
Costs of purchased natural gas	–	3.1	–	3.1	–	3.1
Selling and general expenses	(3.3)	20.4	6.7	23.8	89.1	112.9
Exploration expenses					–	
Geological and geophysical	14.4	0.2	12.6	27.2	–	27.2
Dry holes and previously suspended exploration costs	70.9	–	2.3	73.2	–	73.2
Other exploratory costs, including undeveloped lease amortization and delay lease rentals	10.9	0.3	21.9	33.1	–	33.1
Total exploration expenses	<u>96.2</u>	<u>0.5</u>	<u>36.8</u>	<u>133.5</u>	<u>–</u>	<u>133.5</u>
Depreciation, depletion and amortization	709.2	146.0	1.7	856.9	8.9	865.8
Impairment of assets	62.9	–	–	62.9	–	62.9
Accretion of asset retirement obligations	43.1	8.6	0.7	52.4	0.1	52.5
Other operating expenses (income)	9.3	2.8	2.1	14.2	(3.2)	11.0
Interest income	(22.0)	–	–	(22.0)	(12.2)	(34.2)
Interest expense, net of capitalization	0.2	0.4	0.2	0.8	105.1	105.9
Income tax expense (benefit)						
Current income tax expense (benefit)	1.5	3.2	0.2	4.9	0.9	5.8
Deferred income tax expense (benefit)	123.8	8.8	(31.2)	101.4	(28.9)	72.5
Total income tax expense (benefit)	<u>125.3</u>	<u>12.0</u>	<u>(31.0)</u>	<u>106.3</u>	<u>(28.0)</u>	<u>78.3</u>
Other segment costs (income)	6.9	0.1	0.3	7.3	(44.0)	(36.7)
Segment income (loss) - including NCI ¹	<u>\$ 561.9</u>	<u>\$ 49.0</u>	<u>\$ (12.5)</u>	<u>\$ 598.4</u>	<u>\$ (111.9)</u>	<u>\$ 486.5</u>
Additions to property, plant, equipment	\$ 601.7	\$ 137.9	\$ 71.8	\$ 811.4	\$ 29.2	\$ 840.6
Total assets at year-end	6,953.8	1,919.8	302.0	9,175.6	491.9	9,667.5

¹ Includes results attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S - Business Segments (Continued)

	Exploration and Production				Corporate, and Discontinued Operations	Consolidated Total
(Millions of dollars)	United States ¹	Canada	Other	Total E&P		
Year ended December 31, 2023						
Revenue from production	\$ 2,921.8	\$ 443.8	\$ 11.0	\$ 3,376.6	\$ —	\$ 3,376.6
Sales of purchased natural gas	—	72.2	—	72.2	—	72.2
Gain on sales of assets and other operating income	6.5	1.5	—	8.0	3.3	11.3
Total revenues and other income	2,928.3	517.5	11.0	3,456.8	3.3	3,460.1
Lease operating expenses						
Lease operating expenses and taxes other than income	532.3	144.7	1.9	678.9	—	678.9
Repair and maintenance	53.2	5.0	—	58.2	—	58.2
Workovers	45.2	2.1	—	47.3	—	47.3
Total lease operating expenses	630.7	151.8	1.9	784.4	—	784.4
Severance and ad valorem taxes	41.4	1.4	—	42.8	—	42.8
Transportation, gathering and processing	157.0	76.0	—	233.0	—	233.0
Costs of purchased natural gas	—	51.7	—	51.7	—	51.7
Selling and general expenses	11.8	16.5	9.4	37.7	81.2	118.9
Exploration expenses					—	
Geological and geophysical	6.6	0.1	19.4	26.1	—	26.1
Dry holes and previously suspended exploration costs	153.1	—	16.7	169.8	—	169.8
Other exploratory costs, including undeveloped lease amortization and delay lease rentals	14.9	0.4	23.6	38.9	—	38.9
Total exploration expenses	174.6	0.5	59.7	234.8	—	234.8
Depreciation, depletion and amortization	706.0	142.2	2.3	850.5	11.0	861.5
Accretion of asset retirement obligations	37.8	7.8	0.4	46.0	0.1	46.1
Other operating expenses (income)	27.2	15.5	8.1	50.8	(4.4)	46.4
Interest income	(3.3)	—	—	(3.3)	(9.3)	(12.6)
Interest expense, net of capitalization	0.1	0.2	0.2	0.5	111.9	112.4
Income tax expense (benefit)						
Current income tax expense (benefit)	3.1	3.7	0.6	7.4	8.8	16.2
Deferred income tax expense (benefit)	229.6	7.5	(6.7)	230.4	(50.6)	179.8
Total income tax expense (benefit)	232.7	11.2	(6.1)	237.8	(41.8)	196.0
Other segment costs	7.2	1.1	0.6	8.9	12.1	21.0
Segment income (loss) - including NCI ¹	\$ 905.1	\$ 41.6	\$ (65.5)	\$ 881.2	\$ (157.5)	\$ 723.7
Additions to property, plant, equipment	\$ 671.3	\$ 206.2	\$ 13.1	\$ 890.6	\$ 24.2	\$ 914.8
Total assets at year-end	7,107.0	2,080.0	213.3	9,400.2	366.5	9,766.7

¹ Includes results attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note S – Business Segments (Continued)

Geographic Information

	Certain long-lived assets at December 31 ¹			
<i>(Millions of dollars)</i>	United States	Canada	Other	Total
2025	\$ 6,236.8	\$ 1,460.6	\$ 438.9	\$ 8,136.3
2024	6,415.9	1,389.5	249.2	8,054.6
2023	6,555.0	1,497.3	172.8	8,225.1

¹ Certain long-lived assets at December 31 represent total non-current assets, excluding investments, right-of-use operating lease assets, non-current receivables, deferred tax assets and other intangible assets.

Note T – Leases

Nature of Leases

The Company has entered into various operating and financial leases such as a natural gas processing plant, floating production storage and off-take vessels, buildings, marine vessels, vehicles, drilling rigs, pipelines and other oil and natural gas field equipment.

Remaining lease terms range from 1 year to 15 years, some of which may include options to extend leases for multi-year periods and others which include options to terminate the leases within 1 month.

Options to extend lease terms are at the Company's discretion. Early lease terminations are a combination of Company discretion and mutual agreement between the Company and the lessor. Purchase options also exist for certain leases.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note T - Leases (Continued)

Related Expenses

Expenses related to finance and operating leases (both short-term and long-term) included in the Consolidated Financial Statements are as follows.

<i>(Thousands of dollars)</i>	Financial Statements Category	Year Ended December 31,	
		2025	2024
Operating lease ^{1,2}	Lease operating expenses	\$ 342,520	\$ 411,303
Operating lease ²	Transportation, gathering and processing	8,308	16,117
Operating lease ²	Selling and general expenses	10,405	10,990
Operating lease ²	Other operating expense	467	6,622
Operating lease ²	Exploration expenses	14,335	38,974
Operating lease ²	Property, plant and equipment	175,400	277,170
Operating lease ²	Asset retirement obligations	85,690	10
Finance lease			
Amortization of asset	Depreciation, depletion and amortization	1,026	855
Interest on lease liabilities	Interest expense, net	229	193
Sublease income	Other income	(240)	(1,143)
Net lease expense		<u>\$ 638,140</u>	<u>\$ 761,091</u>

¹ *Variable lease expenses.* For the years ended December 31, 2025 and 2024, included variable lease expenses of \$34.6 million and \$42.3 million, respectively, primarily related to operating costs at a natural gas processing plant in our Canada Onshore business.

² *Short-term leases due within 12 months.* The table below shows amounts included in the Consolidated Financial Statements related to short-term leases due within 12 months. These expenses primarily related to drilling rigs and other oil and natural gas field equipment.

<i>(Thousands of dollars)</i>	Financial Statements Category	Year Ended December 31,	
		2025	2024
	Lease operating expenses	\$ 159,746	\$ 236,402
	Transportation, gathering and processing	8,308	12,993
	Selling and general expenses	1,918	772
	Other operating expense	16	6,230
	Exploration expenses	13,211	38,500
	Property, plant and equipment	96,909	97,104
	Asset retirement obligations	65,418	10
	Total short-term lease expense	<u>\$ 345,526</u>	<u>\$ 392,011</u>

Maturity of Lease Liabilities

<i>(Thousands of dollars)</i>	Operating Leases	Finance Leases	Total
2026	\$ 315,609	\$ 3,302	\$ 318,911
2027	146,130	3,302	149,432
2028	63,009	3,302	66,311
2029	60,214	2,491	62,705
2030	58,445	1,885	60,330
Remaining	366,321	774	367,095
Total future minimum lease payments	1,009,728	15,056	1,024,784
Less imputed interest	(193,121)	(2,402)	(195,523)
Present value of lease liabilities ¹	<u>\$ 816,607</u>	<u>\$ 12,654</u>	<u>\$ 829,261</u>

¹ Includes both the current and long-term portion of the lease liabilities.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Note T - Leases (Continued)

Lease Term and Discount Rate

	<u>December 31, 2025</u>	<u>December 31, 2024</u>
Weighted average remaining lease term:		
Operating leases	7 years	8 years
Finance leases	5 years	6 years
Weighted average discount rate:		
Operating leases	5.5 %	5.7 %
Finance leases	5.4 %	4.9 %

Other Information

	<u>Year Ended December 31,</u>	
<i>(Thousands of dollars)</i>	<u>2025</u>	<u>2024</u>
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	\$ 258,564	\$ 328,847
Operating cash flows from finance leases	339	311
Financing cash flows from finance leases	1,238	665
Right-of-use assets obtained in exchange for lease liabilities:		
Operating leases ¹	\$ 247,566	\$ 349,312
Finance leases ²	8,845	1,749

¹ For the year ended December 31, 2025, right-of-use assets, obtained in exchange for operating lease liabilities, primarily included \$153.7 million for a drill ship operating lease extension used in our U.S. Offshore business and \$72.2 million for a drilling rig and two support vessels in our Vietnam business. December 31, 2024 included \$254.1 million for a drill ship operating lease extension in our U.S. Offshore business and \$52.7 million related to two drilling rigs and several natural gas compressors in our U.S. Onshore business.

² For the year ended December 31, 2025, right-of-use assets obtained in exchange for finance lease liabilities primarily included \$8.8 million related to computing equipment in the U.S.

Note U - Subsequent Event

On January 28, 2026, the Board of Directors of Murphy Oil Corporation (NYSE: MUR) declared a quarterly cash dividend on the Common Stock of Murphy Oil Corporation of \$0.35 per share, which on an annualized basis would be \$1.40 per share. The dividend is payable on March 2, 2026, to stockholders of record as of February 17, 2026.

In January 2026, the Company completed a series of transactions regarding its long-term debt arrangements and RCF. In particular, the Company closed a public offering of \$500.0 million aggregate principal amount of its 2034 Notes, used the proceeds to redeem an aggregate \$227.5 million of its outstanding 2027 Notes and 2028 Notes, repaid \$100.0 million that was outstanding on the previous RCF, as of December 31, 2025, and expects to use the remaining proceeds to cover transaction-related fees and expenses and for general corporate purposes. In addition, the Company entered into an amendment to its credit agreement which increased its RCF capacity from \$1.35 billion to \$2.0 billion and extended the term of the agreement to 2031. See [Note F](#) for additional information on these transactions.

Subsequent to the balance sheet date, the Company announced oil discoveries at the Cello #1 (Mississippi Canyon 385) and Banjo #1 (Mississippi Canyon 385) exploration wells in the Gulf of America and dry holes at the Civette-1X (Block CI-502) and Caracal-1X (Block CI-102) exploration wells in Côte d'Ivoire. A portion of the Civette-1X dry hole charge was recorded in 2025. The remainder of Civette-1X and all charges related to the Caracal-1X well will be recorded in the first quarter of 2026. See [Note D](#) for additional information.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The following unaudited schedules are presented in accordance with required disclosures about Oil and Gas Producing Activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information concerning some of the schedules follows:

SCHEDULE 1 - SUMMARY OF TOTAL PROVED EQUIVALENT RESERVES

SCHEDULE 2 - SUMMARY OF PROVED CRUDE OIL RESERVES

SCHEDULE 3 - SUMMARY OF PROVED NATURAL GAS LIQUIDS RESERVES

SCHEDULE 4 - SUMMARY OF PROVED NATURAL GAS RESERVES

Reserves of oil and natural gas are estimated by the Company's or independent engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgments are required to estimate reserves. Reserve estimates and future cash flows are based on the average market prices for sales of oil and natural gas on the first calendar day of each month during the year. The average prices used for 2025 were \$65.34 per BBL for crude oil (WTI) and \$3.39 per MCF for natural gas (Henry Hub). The average prices used for 2024 were \$75.48 per BBL for crude oil (WTI) and \$2.13 per MCF for natural gas (Henry Hub). The average prices used for 2023 were \$78.22 per BBL for crude oil (WTI) and \$2.64 per MCF for natural gas (Henry Hub). Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data (including hydrocarbon prices, operating costs, and development costs) and commercially available technologies to establish "reasonable certainty" of economic producibility. Estimates are presented in millions of barrels of oil equivalents and dollars and billions of cubic feet rounded to one decimal. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses common industry-accepted methods for subsurface evaluations, including performance, volumetric and analog-based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates. The approach was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, volumes consumed for fuel and/or shrinkage from the extraction of NGLs.

All oil and natural gas reserves are from consolidated subsidiaries (including NCI) and proportionately consolidated joint ventures. The Company has no proved reserves attributable to investees accounted for by the equity method.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued

**SCHEDULE 7 - STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO
PROVED OIL AND GAS RESERVES**

GAAP requires calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Schedule 7 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2025.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 1 - Summary of Total Proved Equivalent Reserves Based on Average Prices for 2022 - 2025

	Equivalents			
	Total	United States	Canada	Other
<i>(Millions of barrels of oil equivalent)</i>				
Proved developed and undeveloped reserves:				
December 31, 2022	715.4	357.0	357.8	0.6
Revisions of previous estimates	(13.3)	(13.3)	0.2	(0.2)
Improved recovery	0.4	—	0.4	—
Extensions and discoveries	112.6	12.7	87.3	12.6
Sale of properties	(5.2)	—	(5.2)	—
Production	(70.4)	(45.3)	(25.0)	(0.1)
December 31, 2023	739.5	311.1	415.5	12.9
Revisions of previous estimates	14.3	8.1	6.3	(0.1)
Improved recovery	11.3	11.3	—	—
Extensions and discoveries	31.4	16.0	15.4	—
Production	(67.5)	(39.1)	(28.3)	(0.1)
December 31, 2024	729.0	307.4	408.9	12.7
Revisions of previous estimates	26.0	18.0	7.1	0.9
Extensions and discoveries	43.0	4.9	38.1	—
Purchases of properties	4.3	4.3	—	—
Sale of properties	(3.4)	(3.4)	—	—
Production	(68.9)	(39.3)	(29.5)	(0.1)
December 31, 2025 ¹	730.0	291.9	424.6	13.5
Proved developed reserves:				
December 31, 2022	436.0	264.2	171.3	0.5
December 31, 2023	425.5	223.2	202.0	0.3
December 31, 2024	436.2	218.9	217.1	0.2
December 31, 2025 ²	418.9	197.8	220.9	0.2
Proved undeveloped reserves:				
December 31, 2022	279.4	92.8	186.5	0.1
December 31, 2023	314.0	87.9	213.5	12.6
December 31, 2024	292.8	88.5	191.8	12.5
December 31, 2025 ³	311.1	94.1	203.7	13.3

¹ Total and United States includes proved reserves of 15.0 MMBOE, consisting of 13.9 MMBBL of oil, 0.4 MMBBL of NGLs and 4.2 BCF of natural gas attributable to the noncontrolling interest in MP GOM.

² Total and United States includes proved developed reserves of 13.1 MMBOE, consisting of 12.1 MMBBL of oil, 0.4 MMBBL of NGLs and 3.9 BCF of natural gas attributable to the noncontrolling interest in MP GOM.

³ Total and United States includes proved undeveloped reserves of 1.9 MMBOE, consisting of 1.8 MMBBL of oil and 0.3 BCF of natural gas attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 1 - Summary of Total Proved Equivalent Reserves Based on Average Prices for 2022 - 2025
(Continued)

2025 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2025 resulted predominantly from performance adjustments in the Tupper Montney and the Eagle Ford Shale, revisions in the Gulf of America for additional field life at the Chinook #8 location, in the Cascade and Chinook fields, due to the Pioneer FPSO purchase, partially offset by the effects of lower oil prices and higher gas prices that increased royalty rates and accelerated royalty incentive payouts in the Tupper Montney.

Extensions and discoveries - In 2025, proved equivalent reserves were added for drilling activities predominantly in the Tupper Montney and the Eagle Ford Shale.

Purchases and sales of properties - In 2025, the Company acquired incremental working interest in various properties in the Eagle Ford Shale and divested a minor area of the Eagle Ford Shale in separate transactions.

2024 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2024 resulted predominantly from performance adjustments in the Tupper Montney and the Eagle Ford Shale and positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in the Tupper Montney.

Improved Recovery - Proved equivalent reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved equivalent reserves were added for drilling activities predominantly in the Tupper Montney, the Eagle Ford Shale, and projects in the Gulf of America.

2023 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2023 resulted predominantly from lower commodity prices in the U.S. and performance adjustments in the Tupper Montney and the Eagle Ford Shale. These negative revisions were partially offset by positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in the Tupper Montney.

Extensions and discoveries - In 2023, proved equivalent reserves were added for drilling and expansion activities predominantly in the Tupper Montney, the Eagle Ford Shale, and Vietnam.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest, in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 2 - Summary of Proved Crude Oil Reserves Based on Average Prices for 2022 - 2025

<i>(Millions of barrels)</i>	Total	United States	Canada	Other
Proved developed and undeveloped crude oil reserves:				
December 31, 2022	303.6	263.6	39.5	0.5
Revisions of previous estimates	(10.8)	(8.9)	(1.8)	(0.1)
Improved recovery	0.4	–	0.4	–
Extensions and discoveries	22.5	8.9	1.5	12.1
Sale of properties	(2.0)	–	(2.0)	–
Production	(37.9)	(35.6)	(2.2)	(0.1)
December 31, 2023	275.8	228.0	35.4	12.4
Revisions of previous estimates	6.6	6.6	0.1	(0.1)
Improved recovery	10.7	10.7	–	–
Extensions and discoveries	16.6	10.7	5.9	–
Production	(34.6)	(30.8)	(3.7)	(0.1)
December 31, 2024	275.1	225.2	37.7	12.2
Revisions of previous estimates	20.2	18.2	1.8	0.2
Extensions and discoveries	5.7	3.4	2.3	–
Purchases of properties	3.5	3.5	–	–
Sales of properties	(1.8)	(1.8)	–	–
Production	(34.0)	(30.3)	(3.6)	(0.1)
December 31, 2025 ¹	268.7	218.2	38.2	12.3
Proved developed crude oil reserves:				
December 31, 2022	209.0	194.4	14.2	0.4
December 31, 2023	186.3	163.7	22.3	0.3
December 31, 2024	184.7	164.1	20.4	0.2
December 31, 2025 ²	173.1	150.8	22.1	0.2
Proved undeveloped crude oil reserves:				
December 31, 2022	94.6	69.2	25.3	0.1
December 31, 2023	89.5	64.3	13.1	12.1
December 31, 2024	90.4	61.1	17.3	12.0
December 31, 2025 ³	95.6	67.4	16.1	12.1

¹ Total and United States includes proved reserves of 13.9 MMBBL attributable to the noncontrolling interest in MP GOM.

² Total and United States includes proved developed reserves of 12.1 MMBBL attributable to the noncontrolling interest in MP GOM.

³ Total and United States includes proved undeveloped reserves of 1.8 MMBBL attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 2 - Summary of Proved Crude Oil Reserves Based on Average Prices for 2022 - 2025 (Continued)

2025 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The crude oil reserves revisions in 2025 resulted predominantly from performance adjustments in the Tupper Montney and the Eagle Ford Shale, revisions in the Gulf of America for additional field life at the Chinook #8 location, in the Cascade and Chinook fields, due to the Pioneer FPSO purchase, partially offset by the effects of lower oil prices.

Extensions and discoveries - In 2025, proved oil reserves were added for drilling activities predominantly in the Eagle Ford Shale and in the Kaybob Duvernay in Canada.

Purchases and sales of properties - In 2025, the Company acquired incremental working interest in various properties in the Eagle Ford Shale and divested a minor area of the Eagle Ford Shale in separate transactions.

2024 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The crude oil reserves revisions in 2024 resulted predominantly from performance adjustments in the Eagle Ford Shale and the Gulf of America.

Improved Recovery - Proved oil reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved oil reserves were added for drilling activities predominantly in the Eagle Ford Shale and the Gulf of America.

2023 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The negative crude oil reserves revisions in 2023 resulted predominantly from impacts of lower commodity prices in the U.S. and performance adjustments in the Eagle Ford Shale and the Gulf of America.

Extensions and discoveries - In 2023, proved oil reserves were added for drilling and expansion activities predominantly in the Eagle Ford Shale and Vietnam.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 3 - Summary of Proved Natural Gas Liquids Reserves Based on Average Prices for 2022 - 2025

<i>(Millions of barrels)</i>	Total	United States	Canada	Other
Proved developed and undeveloped NGL reserves:				
December 31, 2022	41.7	37.6	4.1	—
Revisions of previous estimates	(1.4)	(1.2)	(0.2)	—
Extensions and discoveries	2.0	1.7	0.3	—
Sale of properties	(0.6)	—	(0.6)	—
Production	(4.1)	(3.8)	(0.3)	—
December 31, 2023	37.6	34.3	3.3	—
Revisions of previous estimates	1.2	0.3	0.9	—
Improved recovery	0.4	0.4	—	—
Extensions and discoveries	2.9	2.4	0.5	—
Production	(3.5)	(3.3)	(0.2)	—
December 31, 2024	38.6	34.1	4.5	—
Revisions of previous estimates	1.4	1.2	0.2	—
Extensions and discoveries	1.1	0.7	0.4	—
Purchases of properties	0.4	0.4	—	—
Sale of properties	(0.8)	(0.8)	—	—
Production	(4.0)	(3.8)	(0.2)	—
December 31, 2025 ¹	36.7	31.8	4.9	—
Proved developed NGL reserves:				
December 31, 2022	29.7	27.4	2.3	—
December 31, 2023	25.9	24.1	1.8	—
December 31, 2024	24.1	21.9	2.2	—
December 31, 2025 ²	21.7	19.2	2.5	—
Proved undeveloped NGL reserves:				
December 31, 2022	12.0	10.2	1.8	—
December 31, 2023	11.7	10.2	1.5	—
December 31, 2024	14.5	12.2	2.3	—
December 31, 2025	15.0	12.6	2.4	—

¹ Total and United States includes total proved reserves of 0.4 MMBBL attributable to the noncontrolling interest in MP GOM.

² Total and United States includes proved developed reserves of 0.4 MMBBL attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 3 - Summary of Proved Natural Gas Liquids Reserves Based on Average Prices for 2022 - 2025
(Continued)

2025 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The NGL reserves revisions in 2025 resulted predominantly from performance adjustments in the Eagle Ford Shale and the Gulf of America, partially offset by lower commodity prices in the United States.

Extensions and discoveries - In 2025, proved NGL reserves were added for drilling activities predominantly in the Tupper Montney and the Eagle Ford Shale.

Purchases and sales of properties - In 2025, the Company acquired incremental working interest in various properties in the Eagle Ford Shale and divested a minor area of the Eagle Ford Shale in separate transactions.

2024 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The NGL reserves revisions in 2024 resulted predominantly from performance adjustments in the Tupper Montney and the Eagle Ford Shale, and positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in the Tupper Montney.

Improved Recovery - Proved NGL reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved NGL reserves were added for drilling activities predominantly in the Tupper Montney and the Eagle Ford Shale.

2023 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The negative NGL reserves revisions in 2023 resulted predominantly from impacts of lower commodity prices in the U.S. and performance adjustments in the Eagle Ford Shale. These revisions were partially offset by improvements in the Gulf of America.

Extensions and discoveries - In 2023, proved NGL reserves were added for drilling and expansion activities predominantly in the Eagle Ford Shale.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 4 - Summary of Proved Natural Gas Reserves Based on Average Prices for 2022 - 2025

<i>(Billions of cubic feet)</i>	Total	United States	Canada	Other
Proved developed and undeveloped natural gas reserves:				
December 31, 2022	2,219.9	334.9	1,884.8	0.2
Revisions of previous estimates	(6.9)	(19.0)	12.1	—
Extensions and discoveries	528.9	12.3	513.8	2.8
Sale of properties	(15.6)	—	(15.6)	—
Production	(170.1)	(35.1)	(135.0)	—
December 31, 2023	2,556.2	293.1	2,260.1	3.0
Revisions of previous estimates	39.1	7.7	31.4	—
Improved recovery	1.2	1.2	—	—
Extensions and discoveries	71.4	17.0	54.4	—
Production	(176.1)	(30.1)	(146.0)	—
December 31, 2024	2,491.8	288.9	2,199.9	3.0
Revisions of previous estimates	26.7	(8.7)	30.8	4.6
Extensions and discoveries	217.2	4.7	212.5	—
Purchases of properties	2.4	2.4	—	—
Sale of properties	(5.1)	(5.1)	—	—
Production	(185.3)	(31.0)	(154.3)	—
December 31, 2025 ^{1,2}	2,547.7	251.2	2,288.9	7.6
Proved developed natural gas reserves:				
December 31, 2022	1,183.1	254.1	928.8	0.2
December 31, 2023	1,279.3	212.4	1,066.7	0.2
December 31, 2024	1,364.2	196.8	1,167.2	0.2
December 31, 2025 ^{2,3}	1,345.1	166.4	1,178.5	0.2
Proved undeveloped natural gas reserves:				
December 31, 2022	1,036.8	80.8	956.0	—
December 31, 2023	1,276.9	80.7	1,193.4	2.8
December 31, 2024	1,127.6	92.1	1,032.7	2.8
December 31, 2025 ⁴	1,202.6	84.8	1,110.4	7.4

¹ Total and United States includes total proved reserves of 4.2 BCF attributable to the noncontrolling interest in MP GOM.

² Includes proved natural gas reserves to be consumed in operations as fuel of 54.2 BCF, 35.1 BCF and 7.4 BCF for the U.S., Canada and Other, respectively, with 1.7 BCF attributable to the noncontrolling interest in MP GOM.

³ Total and United States includes proved developed reserves of 3.9 BCF attributable to the noncontrolling interest in MP GOM.

⁴ Total and United States includes proved undeveloped reserves of 0.3 BCF attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 4 - Summary of Proved Natural Gas Reserves Based on Average Prices for 2022 - 2025 (Continued)

2025 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The natural gas reserves revisions in 2025 resulted predominantly from performance adjustments in the Tupper Montney, partially offset by negative revisions due to increased royalty rates and accelerated royalty incentive payouts resulting from higher commodity prices in the Tupper Montney and the effects of reduced oil price in the Eagle Ford Shale.

Extensions and discoveries - In 2025, proved natural gas reserves were added for drilling activities predominantly in the Tupper Montney and the Eagle Ford Shale.

Purchases and sales of properties - In 2025, the Company acquired incremental working interest in various properties in the Eagle Ford Shale and divested a minor area of the Eagle Ford Shale in separate transactions

2024 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The natural gas reserves revisions in 2024 resulted predominantly from performance adjustments in the Tupper Montney and the Eagle Ford Shale, and positive revisions due to reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in the Tupper Montney.

Improved Recovery - Proved natural gas reserves were added in 2024 for the non-operated St. Malo waterflood in the Gulf of America.

Extensions and discoveries - In 2024, proved natural gas reserves were added for drilling activities predominantly in the Tupper Montney and the Eagle Ford Shale.

2023 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2023 resulted predominantly from lower commodity prices in the U.S. and performance adjustments in the Tupper Montney and the Eagle Ford Shale. These negative revisions were partially offset by positive revisions in the Gulf of America, as well as reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in the Tupper Montney.

Extensions and discoveries - In 2023, proved natural gas reserves were added for drilling and expansion activities predominantly in the Tupper Montney.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its non-operated Placid Montney assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 5 - Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

<i>(Millions of dollars)</i>	United States	Canada	Other	Total
Year ended December 31, 2025				
Property acquisition costs				
Unproved	\$ 5.5	\$ –	\$ –	\$ 5.5
Proved	23.6	–	–	23.6
Total acquisition costs	29.1	–	–	29.1
Exploration costs	71.6	0.3	144.3	216.2
Development costs	696.2	152.5	102.9	951.6
Total costs incurred	796.9	152.8	247.2	1,196.9
Charged to expense				
Dry hole expense	(0.9)	–	31.0	30.1
Geophysical and other costs	34.3	0.3	35.3	69.9
Total charged to expense ¹	33.4	0.3	66.3	100.0
Property additions	<u>\$ 763.5</u>	<u>\$ 152.5</u>	<u>\$ 180.9</u>	<u>\$ 1,096.9</u>
Year ended December 31, 2024				
Property acquisition costs				
Unproved	\$ 7.8	\$ 0.2	\$ –	\$ 8.0
Proved	–	–	–	–
Total acquisition costs	7.8	0.2	–	8.0
Exploration costs	85.3	0.4	60.2	145.9
Development costs	598.7	137.7	45.1	781.5
Total costs incurred	691.8	138.3	105.3	935.4
Charged to expense				
Dry hole expense	70.9	–	2.3	73.2
Geophysical and other costs	19.2	0.4	31.2	50.8
Total charged to expense ¹	90.1	0.4	33.5	124.0
Property additions	<u>\$ 601.7</u>	<u>\$ 137.9</u>	<u>\$ 71.8</u>	<u>\$ 811.4</u>
Year ended December 31, 2023				
Property acquisition costs				
Unproved	\$ –	\$ –	\$ 8.5	\$ 8.5
Proved	12.8	–	14.3	27.1
Total acquisition costs	12.8	–	22.8	35.6
Exploration costs	157.8	0.4	39.9	198.1
Development costs	667.2	206.2	7.4	880.8
Total costs incurred	837.8	206.6	70.1	1,114.5
Charged to expense				
Dry hole expense	153.1	–	16.7	169.8
Geophysical and other costs	13.4	0.4	40.3	54.1
Total charged to expense ¹	166.5	0.4	57.0	223.9
Property additions	<u>\$ 671.3</u>	<u>\$ 206.2</u>	<u>\$ 13.1</u>	<u>\$ 890.6</u>

¹ Excludes undeveloped lease amortization for the years ended 2025, 2024 and 2023 of \$11.7 million, \$9.6 million and \$10.9 million, respectively.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 6 - Results of Operations for Oil and Gas Producing Activities ¹

<i>(Millions of dollars)</i>	United States	Canada	Other	Total
Year ended December 31, 2025				
Revenues				
Crude oil and natural gas liquids sales	\$ 2,047.4	\$ 254.4	\$ 5.7	\$ 2,307.5
Natural gas sales	106.5	275.8	—	382.3
Total oil and natural gas revenues	2,153.9	530.2	5.7	2,689.8
Other operating revenues	5.9	1.7	10.0	17.6
Total revenues	2,159.8	531.9	15.7	2,707.4
Costs and expenses				
Lease operating expenses	577.1	185.6	2.5	765.2
Severance and ad valorem taxes	37.7	1.5	—	39.2
Transportation, gathering and processing	107.0	92.7	—	199.7
Exploration costs charged to expense	33.5	0.3	66.2	100.0
Undeveloped lease amortization	7.5	0.1	4.1	11.7
Depreciation, depletion and amortization	822.1	144.8	2.5	969.4
Accretion of asset retirement obligations	46.6	10.3	0.7	57.6
Impairment of assets	115.0	—	—	115.0
Selling and general expenses	13.7	23.7	8.8	46.2
Other expenses (benefits)	13.4	3.5	(0.4)	16.5
Total costs and expenses	1,773.6	462.5	84.4	2,320.5
Results of operations before taxes	386.2	69.4	(68.7)	386.9
Income tax expense (benefit)	77.7	14.6	(2.1)	90.2
Results of operations	\$ 308.5	\$ 54.8	\$ (66.6)	\$ 296.7
Year ended December 31, 2024				
Revenues				
Crude oil and natural gas liquids sales	\$ 2,436.0	\$ 272.3	\$ 6.6	\$ 2,714.9
Natural gas sales	67.8	232.2	—	300.0
Sales of purchased natural gas	—	3.7	—	3.7
Total oil and natural gas revenues	2,503.8	508.2	6.6	3,018.6
Other operating revenues	4.5	1.5	—	6.0
Total revenues	2,508.3	509.7	6.6	3,024.5
Costs and expenses				
Lease operating expenses	749.9	185.5	1.6	937.0
Severance and ad valorem taxes	37.8	1.4	—	39.2
Transportation, gathering and processing	130.9	79.9	—	210.8
Costs of purchased natural gas	—	3.1	—	3.1
Exploration costs charged to expense	90.0	0.4	33.5	123.9
Undeveloped lease amortization	6.2	0.1	3.3	9.6
Depreciation, depletion and amortization	709.2	146.0	1.7	856.9
Accretion of asset retirement obligations	43.1	8.6	0.7	52.4
Impairment of assets	62.9	—	—	62.9
Selling and general expenses	(3.3)	20.4	6.7	23.8
Other expenses (benefits)	(5.6)	3.3	2.6	0.3
Total costs and expenses	1,821.1	448.7	50.1	2,319.9
Results of operations before taxes	687.2	61.0	(43.5)	704.6
Income tax expense (benefit)	125.3	12.0	(31.0)	106.3
Results of operations	\$ 561.9	\$ 49.0	\$ (12.5)	\$ 598.4

¹ Results exclude corporate overhead, interest and discontinued operations. Results include amounts attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 6 - Results of Operations for Oil and Gas Producing Activities ¹ (Continued)

<i>(Millions of dollars)</i>	United States	Canada	Other	Total
Year ended December 31, 2023				
Revenues				
Crude oil and natural gas liquids sales	\$ 2,829.1	\$ 165.7	\$ 11.0	\$ 3,005.8
Natural gas sales	92.7	278.2	–	370.9
Sales of purchased natural gas	–	72.2	–	72.2
Total oil and natural gas revenues	2,921.8	516.1	11.0	3,448.9
Other operating revenues	6.5	1.4	–	7.9
Total revenues	2,928.3	517.5	11.0	3,456.8
Costs and expenses				
Lease operating expenses	630.7	151.8	1.9	784.4
Severance and ad valorem taxes	41.4	1.4	–	42.8
Transportation, gathering and processing	157.0	76.0	–	233.0
Costs of purchased natural gas	–	51.7	–	51.7
Exploration costs charged to expense	166.5	0.4	57.0	223.9
Undeveloped lease amortization	8.1	0.1	2.7	10.9
Depreciation, depletion and amortization	706.0	142.2	2.3	850.5
Accretion of asset retirement obligations	37.8	7.8	0.4	46.0
Selling and general expenses	11.8	16.5	9.4	37.7
Other expenses	31.2	16.8	8.9	56.9
Total costs and expenses	1,790.5	464.7	82.6	2,337.8
Results of operations before taxes	1,137.8	52.8	(71.6)	1,119.0
Income tax expense (benefit)	232.7	11.2	(6.1)	237.8
Results of operations	\$ 905.1	\$ 41.6	\$ (65.5)	\$ 881.2

¹ Results exclude corporate overhead, interest and discontinued operations. Results include amounts attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 7 - Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves ¹

<i>(Millions of dollars)</i>	United States	Canada	Other	Total
December 31, 2025				
Future cash inflows	\$ 15,502.7	\$ 6,850.9	\$ 873.7	\$ 23,227.3
Future development costs	(1,969.6)	(812.6)	(204.0)	(2,986.2)
Future production costs	(6,707.7)	(4,240.9)	(343.4)	(11,292.0)
Future income taxes	(602.4)	(342.8)	(176.2)	(1,121.4)
Future net cash flows	6,223.0	1,454.6	150.1	7,827.7
10% annual discount for estimated timing of cash flows	(2,459.4)	(625.4)	(118.7)	(3,203.5)
Standardized measure of discounted future net cash flows	<u>\$ 3,763.6</u>	<u>\$ 829.2</u>	<u>\$ 31.4</u>	<u>\$ 4,624.2</u>
December 31, 2024				
Future cash inflows	\$ 18,118.1	\$ 6,304.4	\$ 1,012.9	\$ 25,435.4
Future development costs	(2,024.9)	(825.9)	(252.5)	(3,103.3)
Future production costs	(7,645.7)	(4,026.5)	(341.7)	(12,013.9)
Future income taxes	(893.5)	(251.2)	(203.4)	(1,348.1)
Future net cash flows	7,554.0	1,200.8	215.3	8,970.1
10% annual discount for estimated timing of cash flows	(2,887.3)	(486.0)	(200.9)	(3,574.2)
Standardized measure of discounted future net cash flows	<u>\$ 4,666.7</u>	<u>\$ 714.8</u>	<u>\$ 14.4</u>	<u>\$ 5,395.9</u>
December 31, 2023				
Future cash inflows	\$ 18,927.6	\$ 8,012.7	\$ 1,004.2	\$ 27,944.5
Future development costs	(1,685.3)	(769.6)	(304.3)	(2,759.2)
Future production costs	(7,856.2)	(4,223.6)	(288.7)	(12,368.5)
Future income taxes	(1,057.5)	(634.6)	(121.3)	(1,813.4)
Future net cash flows	8,328.6	2,384.9	289.9	11,003.4
10% annual discount for estimated timing of cash flows	(2,840.6)	(1,056.9)	(252.5)	(4,150.0)
Standardized measure of discounted future net cash flows	<u>\$ 5,488.0</u>	<u>\$ 1,328.0</u>	<u>\$ 37.4</u>	<u>\$ 6,853.4</u>

¹ Includes amounts attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 7 - Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves ¹ (Continued)

The following are the principal sources of change in the standardized measure of discounted future net cash flows for the years shown.

<i>(Millions of dollars)</i>	2025	2024	2023
Net changes in prices and production costs ²	\$ (1,126.6)	\$ (1,116.5)	\$ (5,845.6)
Net changes in development costs	46.4	(152.7)	(78.8)
Sales and transfers of oil and natural gas produced, net of production costs	(1,685.7)	(1,824.8)	(2,264.8)
Net change due to extensions and discoveries	122.0	583.7	770.4
Net change due to purchases and sales of proved reserves	62.6	—	(96.1)
Development costs incurred	686.2	668.6	703.7
Accretion of discount	598.3	773.5	1,393.3
Revisions of previous quantity estimates	403.9	(688.1)	(771.5)
Net change in income taxes	121.2	298.8	1,229.6
Net (decrease) increase	(771.7)	(1,457.5)	(4,959.8)
Standardized measure at January 1	5,395.9	6,853.4	11,813.2
Standardized measure at December 31	\$ 4,624.2	\$ 5,395.9	\$ 6,853.4

¹ Includes amounts attributable to the noncontrolling interest in MP GOM.

² The average prices used for crude oil (WTI) were \$65.34/BBL in 2025, \$75.48/BBL in 2024 and \$78.22/BBL in 2023. The average prices used for natural gas (Henry Hub) were \$3.39/MCF in 2025, \$2.13/MCF in 2024 and \$2.64/MCF in 2023.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) - Continued
Schedule 8 - Capitalized Costs Relating to Oil and Gas Producing Activities

<i>(Millions of dollars)</i>	United States	Canada	Other	Total
December 31, 2025				
Unproved oil and natural gas properties ¹	\$ 207.0	\$ 6.4	\$ 16.3	\$ 229.7
Proved oil and natural gas properties	17,417.6	4,865.4	439.1	22,722.1
Gross capitalized costs	17,624.6	4,871.8	455.4	22,951.8
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(118.5)	–	(11.5)	(130.0)
Proved oil and natural gas properties	(11,275.7)	(3,412.0)	(47.0)	(14,734.7)
Net capitalized costs	\$ 6,230.4	\$ 1,459.8	\$ 396.9	\$ 8,087.1
December 31, 2024				
Unproved oil and natural gas properties ¹	\$ 247.3	\$ 6.6	\$ 29.1	\$ 283.0
Proved oil and natural gas properties	16,598.8	4,498.1	246.7	21,343.6
Gross capitalized costs	16,846.1	4,504.7	275.8	21,626.6
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(111.0)	–	(20.7)	(131.7)
Proved oil and natural gas properties	(10,326.2)	(3,116.2)	(44.2)	(13,486.6)
Net capitalized costs	\$ 6,408.9	\$ 1,388.5	\$ 210.9	\$ 8,008.3

¹ Unproved oil and natural gas properties above include costs and associated accumulated amortization of properties that do not have proved reserves; these costs include mineral interests, uncompleted exploratory wells and exploratory wells capitalized pending further evaluation.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(Millions of dollars except per share amounts)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2025					
Revenue from contracts with customers ¹	\$ 672.7	\$ 683.0	\$ 721.0	\$ 613.1	\$ 2,689.8
Income (loss) from continuing operations before income taxes ¹	122.8	34.9	(3.7)	28.9	182.9
Income (loss) from continuing operations ¹	90.0	33.8	(7.8)	22.3	138.3
Net income (loss) including noncontrolling interest	89.4	35.1	(8.3)	22.6	138.8
Net income (loss) attributable to Murphy	73.0	22.3	(3.0)	11.9	104.2
Income (loss) from continuing operations per common share ²					
Basic	0.51	0.15	(0.02)	0.08	0.73
Diluted	0.50	0.15	(0.02)	0.08	0.72
Net income (loss) per common share ²					
Basic	0.51	0.16	(0.02)	0.08	0.73
Diluted	0.50	0.16	(0.02)	0.08	0.72
Cash dividend per common share	0.325	0.325	0.325	0.325	1.300
Year ended December 31, 2024					
Revenue from contracts with customers ¹	\$ 794.8	\$ 801.0	\$ 753.2	\$ 669.6	\$ 3,018.6
Income from continuing operations before income taxes ¹	145.6	189.6	153.8	78.6	567.6
Income from continuing operations ¹	115.5	156.9	151.7	65.2	489.3
Net income including noncontrolling interest	114.7	156.3	151.1	64.4	486.5
Net income attributable to Murphy	90.0	127.7	139.1	50.3	407.1
Income from continuing operations per common share ²					
Basic	0.60	0.84	0.93	0.35	2.73
Diluted	0.60	0.83	0.93	0.34	2.72
Net income per common share ²					
Basic	0.59	0.84	0.93	0.35	2.71
Diluted	0.59	0.83	0.93	0.34	2.70
Cash dividend per common share	0.300	0.300	0.300	0.300	1.200

¹ "Revenue from contracts with customers", "Income (loss) from continuing operations before income taxes", "Income (loss) from continuing operations" and "Net income (loss) including noncontrolling interest" includes results attributable to the noncontrolling interest in MP GOM.

² The sum of quarterly income (loss) from continuing operations per share and net income (loss) per share may not agree with total year net income (loss) per share as each quarterly computation is based on the weighted average of common shares outstanding.

DEFINITIONS

Currencies:

CAD or C\$ - Canadian dollar

USD or US\$ - United States dollar

Units of Measure:

BBL - Barrels

BCF - Billion cubic feet

BOEPD - Barrels of oil equivalent per day

MCF - Thousand cubic feet

MMBBL - Million barrels

MMBOE - Million barrels of oil equivalent

MMBTU - Million British thermal units

MMCF - Million cubic feet

Industry:

AECO - Alberta Energy Company and is the Canadian benchmark price for natural gas

Crude oil - Collectively, crude oil and condensate hydrocarbons

Crude oil, natural gas and natural gas liquids - Collectively, oil and natural gas

Development well - A well that is drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive

Dry hole - An exploratory well that does not find oil or natural gas in commercial quantities

E&P - Exploration and production

Exploratory well - A well drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area

FPSO - Floating production, storage and offloading vessel

Hydrocarbons - Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products

Liquids - Collectively, crude oil, condensate and natural gas liquid hydrocarbons

Net acres or net wells - The portions of gross acres or gross wells owned by the Company

NGLs - Natural gas liquids

NYMEX - New York Mercantile Exchange

OPEC - Organization of the Petroleum Exporting Countries

Operator - The company serving as the manager and often the decision-maker of a drilling or production project

Production Sharing Contract (PSC) - Agreement between extracting company(ies) and a host country regarding each party's share of production after stipulated exploratory and development costs are recovered

QRE - Qualified reserve estimator

Seismic - Two-dimensional or three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons

Working interest - Right to drill and produce oil and natural gas on the leased acreage, as well as the obligation to pay costs

WTI - West Texas Intermediate

Abbreviations:

AIP - Annual Incentive Plan

ARO - Asset retirement obligation

ASC - Accounting Standards Codification

ASU - Accounting Standards Update

BOEM - U.S. Bureau of Ocean Energy Management

DEFINITIONS - Continued

BSEE - U.S. Bureau of Safety and Environmental Enforcement
CERCLA - U.S. Comprehensive Environmental Response, Compensation and Liability Act
CODM - Chief operating decision maker
CRSU - Cash-settled restricted time-based stock unit
DD&A - Depreciation, depletion and amortization
EBITDA - Earnings before interest, taxes, depreciation and amortization
EBITDAX - Earnings before interest, taxes, depreciation and amortization, and exploration expenses
EPA - U.S. Environmental Protection Agency
ESG - Environmental, social and governance
FASB - Financial Accounting Standards Board
FCF - Free cash flow
GAAP - U.S. generally accepted accounting principles
GHG - Greenhouse gas
GHGRP - Greenhouse Gas Reporting Program
IRA - Inflation Reduction Act
MP GOM - MP Gulf of Mexico, LLC
NCI - Noncontrolling interest
NED - Non-employee director
OBBBA - One Big Beautiful Bill Act
OPA - U.S. Oil Pollution Act
OT - Operational technology
PCAOB - Public Company Accounting Oversight Board
PSU - Performance-based restricted stock unit
RCF - Senior unsecured guaranteed revolving credit facility
ROACE - Return on average capital employed
RSU - Time-based restricted stock unit
SAR - Stock appreciation right
SEC - U.S. Securities and Exchange Commission
SOFR - Secured Overnight Financing Rate
TCFD - Task Force on Climate-related Financial Disclosures
WEC - Waste emission charge

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Corporate Information

BOARD OF DIRECTORS

Claiborne P. Deming

Chair of the Board
Retired, President and Chief Executive Officer,
Murphy Oil Corporation

Eric M. Hambly

President and Chief Executive Officer,
Murphy Oil Corporation

Lawrence R. Dickerson

Retired, President and Chief Executive Officer,
Diamond Offshore Drilling, Inc.

Michelle A. Earley

Senior Vice President, Deputy General
Counsel and Corporate Secretary
American Airlines Group, Inc.

Elisabeth W. Keller

Retired, President,
Inglewood Plantation, LLC

R. Madison Murphy

Chair of the Board,
Murphy USA Inc.

Jeffrey W. Nolan

Retired, President and Chief Executive Officer,
Loutre Land and Timber Company

Robert N. Ryan, Jr.

Retired, Vice President,
Chevron Corporation

Laura A. Sugg

Retired, Senior Executive,
ConocoPhillips

Robert B. Tudor, III

Founder and CEO,
Artemis Energy Partners

Committee Members Legend

- Member of Audit Committee
- Member of Compensation Committee
- Member of Finance Committee
- Member of Health, Safety, Environment and Corporate Responsibility Committee
- Member of Nominating and Governance Committee

CORPORATE OFFICERS

Eric M. Hambly

President and Chief Executive Officer

Thomas J. Mireles

Executive Vice President
and Chief Financial Officer

E. Ted Botner

Executive Vice President, General Counsel
and Corporate Secretary

Daniel R. Hanchera

Senior Vice President, Business Development

Maria A. Martinez

Senior Vice President, Human Resources,
Administration and Communications

Paul D. Vaughan

Vice President and Controller

Atif Riaz

Vice President, Investor Relations
and Treasurer

STOCKHOLDER INFORMATION

Annual Meeting

The 2026 Annual Meeting of Stockholders will be held on Wednesday, May 13, 2026, at 10:00 a.m. CDT, in a virtual-only format via live audio webcast at www.virtualshareholdermeeting.com/MUR2026

Common Stock

Listed New York Stock Exchange
Ticker Symbol: MUR

Transfer Agent and Registrar

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Providence, RI 02940-3078
Toll-free: (888) 239-5303
Outside the US: (732) 645-4155

For overnight deliveries:
Computershare
150 Royall Street, Suite 101
Canton, MA 02021

Stockholder website:
www.computershare.com/investor

Stockholder online inquiries:
www-us.computershare.com/Investor/Contact

Documents Available

Copies of the Corporation's 2025 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Annual Proxy Statement filed with the Securities and Exchange Commission, as well as the Corporation's Code of Business Conduct and Ethics, Corporate Governance Guidelines, and charters of the Audit Committee, Compensation Committee, Finance Committee, Health, Safety, Environment and Corporate Responsibility Committee, and Nominating and Governance Committee of the Board of Directors are available, without charge, on our website below or upon written request to:

E. Ted Botner

Executive Vice President, General Counsel
and Corporate Secretary
corporatesecretary@murphyoilcorp.com

Members of the financial community:

Atif Riaz

Vice President, Investor Relations
and Treasurer
investorrelations@murphyoilcorp.com

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Forward-looking Statements

See information regarding forward-looking statements on page 56 of the Form 10-K.



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OUR PURPOSE

We believe in providing energy that empowers people.

OUR MISSION

We challenge the norm, tap into our strong legacy and use our foresight and financial discipline to deliver inspired energy solutions.

OUR VISION

We see a future where we are an industry leader who is positively impacting lives for the next 100 years and beyond.

OUR BEHAVIORS

Do Right Always

- Respect people, safety, environment and the law
- Follow through on commitments
- Share openly and accurately
- Make it better

Stay With It

- Show resilience
- Lean into challenges
- Support each other
- Consider the implications

Think Beyond Possible

- Offer solutions
- Step up and lead
- Don't settle for "good enough"
- Embrace new opportunities