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	**71-0361522**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
9805 Katy Fwy, Suite G-200	**77024**
Houston, Texas	**(Zip Code)**
(Address of principal executive offices)	

(281) 675-9000
(Registrant's telephone number, including area code)

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.

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.

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.

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]
Proved Developed Reserves:	(MMBOE)	(MMBBL)		(BCF)
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.

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

(Millions of barrels of oil equivalent) [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.

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.

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.

		Developed		Undeveloped		Total	
Area *(Thousands of acres)*		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.

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

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, 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.

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 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 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;

- 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.

- 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 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.

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.

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

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 fracking, 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 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 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

- 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 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.

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.

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.

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 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.

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.

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

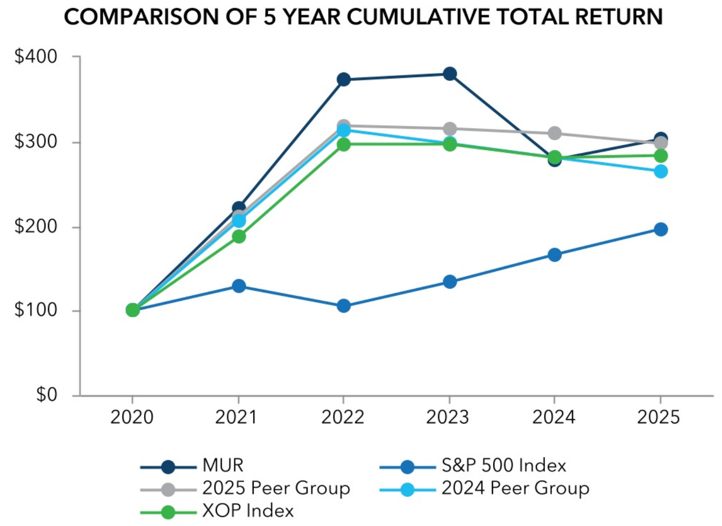
The Board has authorized a share repurchase program whereby the Company can repurchase up to $1,100.0 million of its common stock. Pursuant to the share repurchase program, the Company may repurchase shares through open market purchases, privately negotiated transactions and other means in accordance 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.

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	Expand Energy Corporation	Permian Resources Corporation
Chord Energy Corporation	EOG Resources, Inc.	Range Resources Corporation
Civitas Resources, Inc.	Kosmos Energy Ltd.	SM Energy Company
Coterra Energy Inc.	Magnolia Oil & Gas Corporation	Talos Energy Inc.
Devon Energy Corporation	Matador Resources Company	
Diamondback Energy, Inc.	Ovintiv Inc.	



	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

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 plan[1];
- 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.

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.

Results of Operations

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

(Millions of dollars)	**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.

(Millions of dollars)	**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.

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:

(Average price for the period)	**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

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.

(Barrels per day unless otherwise noted)	**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.

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.

(Barrels per day unless otherwise noted)	**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.

Revenues from Production

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

(Millions of dollars)	**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	**$ 2,689.8**	$ 3,014.9	$ 3,376.6

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.

	(Millions of dollars)			*(Dollars per equivalent barrel)*		
	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	**$ 765.2**	$ 937.0	$ 784.4	**$ 11.10**	$ 13.91	$ 11.18
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	**$ 199.7**	$ 210.8	$ 233.0	**$ 2.90**	$ 3.13	$ 3.32

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

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.

	(Millions of dollars)			(Dollars per equivalent barrel)		
	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	**$ 969.4**	$ 856.9	$ 850.5	**$ 14.06**	$ 12.72	$ 12.12

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.

(Millions of dollars)	**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	**$ 111.7**	$ 133.5	$ 234.8

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.

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.

(Millions of dollars)	**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	**$ (46.4)**	$ 106.5	$ (174.8)

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.

	Year Ended December 31,		
(Millions of dollars)	**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	**$ 1,218.0**	$ 964.8	$ 1,138.1

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

	Year Ended December 31,		
(Millions of dollars)	**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	**1,218.0**	964.8	1,138.1
Less: acquisition of oil and natural gas properties	**29.0**	8.1	35.6
Total capital expenditures excluding acquisition of oil and natural gas properties	**1,189.0**	956.7	1,102.5
Total capital expenditures excluding acquisition of oil and natural gas properties and noncontrolling interest	**$ 1,157.0**	$ 944.7	$ 1,032.3

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, 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

(Millions of dollars)	**2025**	2024
Working capital		
Total current assets	**$ 816.7**	$ 785.3
Total current liabilities	**1,062.7**	942.8
Net working capital liability	**$ (246.0)**	$ (157.5)

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.

Capital Employed

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

		December 31, 2025		December 31, 2024	
(Millions of dollars)		**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	**$**	**6,501.0**	**100.0 %**	$ 6,468.8	100.0 %

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.

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,		
(Millions of dollars, except per share amounts)	**2025**	2024	2023
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.

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

(Millions of dollars)	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.

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.

	Year Ended December 31,		
(Millions of dollars)	**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.

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 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 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.

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.

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.

	Amount of Obligations				
(Millions of dollars)	**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	**$ 6,402.2**	$ 1,209.6	$ 925.9	$ 950.9	$ 3,315.8

[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.

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.

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.

					Remaining Period	
Area	**Commodity**	**Type**	**Volumes (MMCF/D)**	**Price/MCF**	**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

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.

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.

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.

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	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.	Exhibit 2.1 to Form 8-K filed June 5, 2019
2.2	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.	Exhibit 2.2 to Form 8-K filed June 5, 2019
2.3	Contribution Agreement dated as of October 10, 2018 among Murphy Exploration & Production Company – USA, Petrobras America Inc. and MP Gulf of Mexico, LLC	Exhibit 2.1 to Form 10-K filed February 27, 2019
3.1	Certificate of Incorporation of Murphy Oil Corporation, as amended effective May 11, 2005	Exhibit 3.1 to Form 10-K filed February 28, 2011
3.2	By-Laws of Murphy Oil Corporation, as amended effective August 5, 2020	Exhibit 3.2 to Form 10-Q filed August 6, 2020
4.1	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	Exhibit 4.2 to Form 10-K filed March 16, 2005
4.2	Indenture dated as of May 18, 2012 between Murphy Oil Corporation and U.S. Bank National Association, as trustee	Exhibit 4.1 to Form 8-K filed May 18, 2012
4.3	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	Exhibit 4.1 to Form 8-K filed November 30, 2012
4.4	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	Exhibit 4.2 to Form 8-K filed November 27, 2019
4.5	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934	Exhibit 4.9 to Form 10-K filed February 27, 2020
4.6	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	Exhibit 4.2 to Form 8-K filed March 5, 2021
4.7	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	Exhibit 4.2 to Form 8-K filed October 3, 2024
4.8	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)	Exhibit 4.2 to Form 8-K filed January 23, 2026
10.1	Murphy Oil Corporation Annual Incentive Plan	Exhibit 10.3 to Form 10-K filed February 25, 2022
10.2	Murphy Oil Corporation 2020 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 30, 2020

PART IV

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

10.27	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	Exhibit 10.33 to Form 10-K filed February 27, 2025
10.28	Murphy Oil Corporation 2025 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed on March 28, 2025
10.29	Form of employee performance-based restricted stock unit (2025 LTI Plan)	Exhibit 10.35 to Form 10-Q filed November 5, 2025
10.30	Form of employee time-based restricted stock unit – A (2025 LTI Plan)	Exhibit 10.36 to Form 10-Q filed November 5, 2025
10.31	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	Exhibit 10.1 to Form 8-K filed January 6, 2026
*10.32	Form of employee performance-based restricted stock unit — B (2025 LTI Plan)	
*10.33	Form of employee time-based restricted stock unit — B (2025 LTI Plan)	
*10.34	Form of employee time-based restricted stock unit — C (2025 LTI Plan)	
*10.35	Form of employee time-based restricted stock unit — D (2025 LTI Plan)	
19.1	Murphy Oil Corporation Insider Trading Policy	Exhibit 19.1 to Form 10-K filed February 27, 2025
*21.1	Subsidiaries of Murphy Oil Corporation	
*23.1	Consent of Independent Registered Public Accounting Firm	
*23.2	Consent of Ryder Scott Company, L.P.	
*23.3	Consent of McDaniel & Associates Consultants Ltd.	
*23.4	Consent of Netherland, Sewell & Associates, Inc.	
*23.5	Consent of GLJ Petroleum Consultants Ltd.	
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
**32.1	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
97.1	Murphy Oil Corporation Compensation Recoupment Policy	Exhibit 10.29 to Form 10-K filed February 23, 2024
*99.1	Ryder Scott independent reserves audit report for MP GOM JV	
*99.2	Ryder Scott independent reserves audit report for U.S. Onshore	
*99.3	McDaniel independent reserves audit report for Canada Onshore	
*99.4	Netherland, Sewell & Associates, Inc. independent reserves audit report U.S. Gulf of America	
*99.5	GLJ independent reserves audit for Canada Offshore	
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.

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
Eric M. Hambly, President and
Chief Executive Officer

Date: February 25, 2026

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.

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.

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

"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

"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

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.

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.

(Thousands of dollars)	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	**2,227,343**	2,635,660	2,916,252
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	**80,173**	79,165	89,526
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	**382,329**	300,031	370,861
Revenue from production	**2,689,845**	3,014,856	3,376,639
Sales of purchased natural gas [2]			
Canada - Onshore	**—**	3,742	72,215
Total 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

[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.

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	
(Thousands of dollars)	**Cost**	**Net**	Cost	Net
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.

Note D – Property, Plant and Equipment (Continued)

(Thousands of dollars)	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	**$ 191,821**	$ 72,055	$ 49,118

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.

	2025		2024		2023	
(Thousands of dollars)	**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
	$ 191,821	**11**	$ 72,055	8	$ 49,118	4

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,	
(*Thousands of dollars*)	**2025**	2024
Unsold crude oil	**$ 17,560**	$ 18,745
Materials and supplies	**39,724**	36,113
Inventories	**$ 57,284**	$ 54,858

Note F – Financing Arrangements and Debt

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

(Thousands of dollars)	December 31, 2025	December 31, 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.

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.

Note G - Asset Retirement Obligations (Continued)

(Thousands of dollars)	**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.

(Thousands of dollars)	**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

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.

(Thousands of dollars)	**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	**$ 44,552**	**24.4 %**	$ 78,272	13.8 %	$ 195,921	21.3 %

[1] State taxes primarily include Texas and Louisiana.

Note H – Income Taxes (Continued)

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

(Thousands of dollars)	**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.

(Thousands of dollars)	**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.

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.

(Thousands of dollars)	**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	**$ 8,151**	$ 9,979	$ 6,384

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.

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.

(Thousands of dollars)	**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

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.

(Number of stock units)	**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.

(Number of share units)	**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.

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.

Note J – Employee and Retiree Benefit Plans (Continued)

(Thousands of dollars)	Pension Benefits 2025	Pension Benefits 2024	Other Postretirement Benefits 2025	Other Postretirement Benefits 2024
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	**659,494**	655,324	**63,399**	54,994
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	**527,079**	492,120	**—**	—
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	**(136,986)**	(154,406)	**(58,736)**	(50,757)
Fund Status and net plan liability recognized at December 31	**$ (132,415)**	$ (163,204)	**$ (63,399)**	$ (54,994)

[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.

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

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.

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**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.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**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.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**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)

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.

(Thousands of dollars)	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 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 %
	100.0 %	100.0 %

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		
(Thousands of dollars)	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)
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	**416,798**	**310,972**	**74,837**	**30,989**
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	**110,281**	**—**	**92,359**	**17,922**
Total	**$ 527,079**	**$ 310,972**	**$ 167,196**	**$ 48,911**

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		
(Thousands of dollars)	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)
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 O.

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.

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:

(Thousands of dollars)	Hedged Funds and Other Alternative Strategies
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

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.

(Thousands of dollars)	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.

		Gain (Loss)		
(Thousands of dollars)		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.

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.

(Weighted-average shares, except per share amounts)	**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

(Thousands of dollars)	**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 $14.5 million in 2023	**88,119**	78,806	108,912
Non-cash investing activities:			
Asset retirement costs capitalized	**$ 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.

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.

(Thousands of dollars)	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.

	December 31, 2025				December 31, 2024			
(Thousands of dollars)	**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
	$ 22,205	**$ —**	**$ —**	**$ 22,205**	$ 19,469	$ 1,707	$ —	$ 21,176

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 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	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
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**
(*Thousands of dollars*)	**Level 1**	**Level 2**	**Level 3**		
Assets:					
Impaired proved properties					
United States - Offshore	**$ —**	**$ —**	**$ 42,397**	**$ 157,399**	**$ 115,002**

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.

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 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.

(*Number of shares outstanding*)	**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.

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)

(Millions of dollars)	Exploration and Production: United States [1]	Exploration and Production: Canada	Exploration and Production: Other	Exploration and Production: Total E&P	Corporate, and Discontinued Operations	Consolidated Total
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.

Note S – Business Segments (Continued)

	Exploration and Production					
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate, and Discontinued Operations	Consolidated Total
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	2,508.3	509.7	6.6	3,024.6	3.9	3,028.5
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	749.9	185.5	1.6	937.0	—	937.0
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	96.2	0.5	36.8	133.5	—	133.5
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)	125.3	12.0	(31.0)	106.3	(28.0)	78.3
Other segment costs (income)	6.9	0.1	0.3	7.3	(44.0)	(36.7)
Segment income (loss) - including NCI [1]	$ 561.9	$ 49.0	$ (12.5)	$ 598.4	$ (111.9)	$ 486.5
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.

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Note S – Business Segments (Continued)

(Millions of dollars)	Exploration and Production				Corporate, and Discontinued Operations	Consolidated Total
	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.

Note S – Business Segments (Continued)

Geographic Information	Certain long-lived assets at December 31 [1]			
(Millions of dollars)	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.

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.

(Thousands of dollars)	**Financial Statements Category**	**Year Ended December 31, 2025**	Year Ended December 31, 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		**$ 638,140**	$ 761,091

[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.

(Thousands of dollars) **Financial Statements Category**	**Year Ended December 31, 2025**	Year Ended December 31, 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	**$ 345,526**	$ 392,011

Maturity of Lease Liabilities

(Thousands of dollars)	**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]	**$ 816,607**	**$ 12,654**	**$ 829,261**

[1] Includes both the current and long-term portion of the lease liabilities.

Note T – Leases (Continued)

Lease Term and Discount Rate

	December 31, 2025	December 31, 2024
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

	Year Ended December 31,	
(Thousands of dollars)	**2025**	2024
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.

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			
(Millions of barrels of oil equivalent)	Total	United States	Canada	Other
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.

<u>2025 Comments for Proved Equivalent Reserves Changes</u>

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.

<u>2024 Comments for Proved Equivalent Reserves Changes</u>

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.

<u>2023 Comments for Proved Equivalent Reserves Changes</u>

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

(Millions of barrels)	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.

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

(Millions of barrels)	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.

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

(Billions of cubic feet)	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.

<u>2025 Comments for Proved Natural Gas Reserves Changes</u>

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

<u>2024 Comments for Proved Natural Gas Reserves Changes</u>

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.

<u>2023 Comments for Proved Natural Gas Reserves Changes</u>

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

(Millions of dollars)	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	**$ 763.5**	**$ 152.5**	**$ 180.9**	**$ 1,096.9**
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	$ 601.7	$ 137.9	$ 71.8	$ 811.4
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	$ 671.3	$ 206.2	$ 13.1	$ 890.6

[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]

(*Millions of dollars*)	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)

(*Millions of dollars*)	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]

(*Millions of dollars*)	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	**$ 3,763.6**	**$ 829.2**	**$ 31.4**	**$ 4,624.2**
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	$ 4,666.7	$ 714.8	$ 14.4	$ 5,395.9
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	$ 5,488.0	$ 1,328.0	$ 37.4	$ 6,853.4

[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.

(Millions of dollars)	**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

(*Millions of dollars*)	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

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

MURPHY OIL CORPORATION

PERFORMANCE-BASED RESTRICTED STOCK UNIT GRANT AGREEMENT

Performance-Based Restricted Stock Unit Award Number	Name of Grantee	Target Number of Performance-Based Restricted Stock Units Subject to this Grant
[[GRANTNUMBER]]	[[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]]	[[SHARESGRANTED]]

This Performance-Based Restricted Stock Unit Award (this "Award") is granted on and dated [[GRANTDATE]] (the "Grant Date"), by Murphy Oil Corporation, a Delaware corporation (the "Company"), pursuant to and for the purposes of the 2025 Long-Term Incentive Plan (the "Plan"). Any terms used herein and not otherwise defined shall have the meanings set forth in the Plan.

This Agreement is subject to the following terms and provisions. In addition, certain terms and provisions applicable to this Award may be communicated to you in a separate brochure (the "Brochure"). By accepting this Agreement, you agree to the terms and provisions set forth below, in the Plan and in the Brochure.

1. The Company hereby grants to the employee named above (the "Grantee") the target number of Performance-Based Restricted Stock Units set forth above ("Target RSUs"), each equal in value to one share of Common Stock.

2. This Award is subject to the following vesting and time lapse restrictions:

(a) In the event that the Performance Measures as set forth in Section 3 below are satisfied in accordance with the Plan, the size of this Award will be determined by the Committee, and the Grantee will be paid the value of his or her earned Target RSUs in Shares during the first quarter of the fiscal year immediately following the completion of the Performance Measurement Period (as defined below); *provided* that, except as set forth in Sections 2(c), 2(d) and 2(e) below, the Grantee is employed by the Company on both the last day of the Performance Measurement Period and the date that the Committee determines the size of this Award.

(b) In the event that the Grantee's employment terminates any time prior to the date that the Committee determines the size of this Award, except as set forth in Sections 2(c), 2(d) and 2(e) below, he or she will forfeit all Target RSUs pursuant to this Award.

(c) In the event of the Grantee's death, disability, or retirement (as determined in accordance with the Plan), the Grantee will remain eligible to receive a number of earned Target RSUs, prorated based upon the number of months worked pursuant to this Award up to the time of the death, disability, or retirement event. In the event that the Performance Measures are satisfied in accordance with the Plan and, as set forth in Section 3 below, and the size of this Award is determined by the Committee, the Grantee will be paid his or her Shares during the first quarter of the fiscal year immediately following the completion of the Performance Measurement Period.

(d) If the Grantee is not an Executive or a party to a Severance Protection Agreement with the Company at any time during the period beginning on the Grant Date and ending on the date on which a Change in Control occurs, this Award will fully vest and one hundred percent (100%) of the Target RSUs granted will be deemed to be earned at the target level of performance and will be paid in full, without restrictions, upon such Change in Control; *provided*, *however*, that no payment will be made until the first quarter of 202[•] unless such Change in Control also qualifies as a "change in control event" as determined under Section 409A.

(e) If the Grantee is an Executive or is otherwise a party to a Severance Protection Agreement with the Company at any time during the period beginning on the Grant Date and ending on the date on which a Change in Control occurs, this Award will fully vest and one hundred percent (100%) of the Target RSUs granted will be deemed to be earned at the target level of performance and will be paid in full, without restrictions, upon the occurrence of the Grantee's Qualifying Termination of Employment. "Qualifying Termination of Employment" means the termination of the Grantee's employment within the two-year period immediately following a Change in Control (x) by the Company or any of its affiliates without Cause or (y) by the Grantee for Good Reason. Upon a Qualifying Termination of Employment, payment will be made as soon as reasonably practicable following the date of the Qualifying Termination of Employment, less any Shares or amounts deducted for applicable withholding taxes.

(f) For purposes of this Agreement, "Cause" means the occurrence of any of the following:

(i) Any act or omission by the Grantee which constitutes a material willful breach of the Grantee's obligations to the Company or any of its affiliates or the Grantee's continued and willful refusal to substantially perform satisfactorily any duties reasonably required of the Grantee, which results in material injury to the interest or business reputation of the Company or any of its affiliates and which breach, failure or refusal (if susceptible to cure) is not corrected (other than failure to correct by reason of the Grantee's incapacity due to physical or mental illness) within thirty (30) days after written notification thereof to the Grantee by the Company; *provided* that no act or failure to act on the Grantee's part shall be deemed willful unless done or omitted to be done by the Grantee not in good faith and without reasonable belief that the Grantee's action or omission was in the best interest of the Company or its affiliates;

(ii) The Grantee's commission of any dishonest or fraudulent act, which has caused or may reasonably be expected to cause a material injury to the interest or business reputation of the Company or any of its affiliates;

(iii) The Grantee's plea of guilty or *nolo contendere* to or conviction of a felony under the laws of the United States or any state thereof or any other plea or confession of a similar crime in a jurisdiction in which the Company or any of its affiliates conducts business; or

(iv) The Grantee's commission of a fraudulent act or participation in misconduct which leads to a material restatement of the Company's financial statements.

(g) For purposes of this Agreement, "Executive" means the Company's Chief Executive Officer and any other employee with a title of Vice President or above.

(h) For purposes of this Agreement, "Good Reason" means the occurrence of any of the following:

(i) Any material diminution in the Grantee's title, status, position, the scope of duties assigned, responsibilities or authority, including the assignment to the Grantee of any duties, responsibilities or authority in any manner adverse to the Grantee or inconsistent with the duties, responsibilities and authority assigned to the Grantee prior to a Change in Control;

(ii) Any reduction in the Grantee's base salary, annual target cash bonus opportunity or long-term incentive award opportunity immediately prior to a Change in Control;

(iii) A relocation of more than fifty (50) miles from the location of the Grantee's principal job location or office prior to a Change in Control; or

(iv) Any other action or inaction that constitutes a material breach by the Company or any of its affiliates of any employment or similar agreement pursuant to which the Grantee provides services to the Company or any of its affiliates;

provided, that the Grantee provides the Company with a written notice of termination indicating the Grantee's intent to terminate his or her employment for Good Reason within ninety (90) days after the Grantee becoming aware of any circumstances set forth above, that the Grantee provides the Company with at least thirty (30) days following receipt of such notice to remedy such circumstances, and, if the Company fails to remedy such circumstances during such thirty (30) day period, that the Grantee terminates his or her employment no later than sixty (60) days after the end of such thirty (30) day period.

3. The "Performance Measure" for this Award shall be based on and subject to the achievement of (a) the Company's total shareholder return ("TSR") over the Performance Measurement Period as compared to the TSR of the Company's peer group and (b) the Company's TSR over the Performance Measurement Period on an absolute basis.

The number of Target RSUs earned shall be equal to (i) the number of Target RSUs *multiplied by* (ii) the "Relative TSR Achievement Percentage" (as set forth in the table below and finally determined by the Committee) *multiplied by* (iii) the "Absolute TSR Modifier Achievement Percentage" (as set forth in the table below and finally determined by the Committee). Notwithstanding anything to the contrary herein, in no event will the number of earned Target RSUs exceed 250% of the Target RSUs.

a. Relative TSR Performance Goal. The number of Target RSUs initially earned will be based on the Company's percentile ranking in TSR over the Performance Measurement Period as compared to that of the Company's peer group, as set forth in the table below:

TSR Percentile Rank	**Relative TSR Achievement Percentage**
Below 25th Percentile	0%
25th Percentile (Threshold)	50%
50th Percentile (Target)	100%
At or Above 90th Percentile (Maximum)	200%

The Relative TSR Achievement Percentage will be interpolated for points between the Threshold and Maximum performance levels.

b. Absolute TSR Modifier Performance Goal. After taking into account the achievement of the Relative TSR Performance Goal, the number of Target RSUs earned will be further determined based on the Company's cumulative absolute TSR over the Performance Measurement Period, as set forth in the table below:

Absolute TSR	**Absolute TSR Modifier Achievement Percentage**
< 0%	75%
0% to 15%	100%
> 15%	125%

The Absolute TSR Modifier in respect of the Target RSUs will be interpolated for points between the levels specified in the table above.

c. Performance Measurement Period. The "Performance Measurement Period" under this Award is January 1, 202[•] through December 31, 202[•].

4. Provided that the Performance Measures as set forth in Section 3 above are satisfied and Shares are to be paid to the Grantee without restriction, such Shares paid will be the net

Shares earned pursuant to Section 3 above less the number of Shares which must be withheld to satisfy the tax withholding requirements applicable to such payment of Shares.

5. Notwithstanding anything to the contrary in this Agreement, in no event will Grantee be entitled to receive Shares pursuant to this Award that would result in a violation of the individual limits imposed by Section 5(c) of the Plan. In the event the number of Shares that become issuable pursuant to this Award (determined based on the achievement of the Performance Measures in Section 3) would otherwise violate the individual limits set forth in Section 5(c) of the Plan, the Committee shall reduce the number of Shares issuable to the Grantee under this Award such that no such violation will occur, and the number of Shares subject to the portion of the Award that is so reduced will be deemed automatically forfeited and canceled for no consideration.

6. In the event of any relevant change in the capitalization of the Company prior to the issuance of Shares underlying the Target RSUs, the number of Target RSUs may be equitably adjusted pursuant to the Plan to reflect that change.

7. This Award is not assignable except as provided under the Plan in the case of death and is not subject in whole or in part to attachment, execution, or levy of any kind.

8. The Grantee shall have no voting rights with respect to Shares underlying the Target RSUs unless and until such Shares are reflected as issued and outstanding shares on the Company's stock ledger.

9. The Grantee is eligible to receive a payment equivalent to the dividends paid on shares of Common Stock equal in number to the Target RSUs granted hereunder. These dividend equivalents will be accrued over the performance period and included in any Shares issued at the end of the period. In the event that Shares are not earned, the accompanying accrued dividend equivalents will be forfeited.

10. The Grantee hereby acknowledges and agrees that the Grantee and the Award are subject to the terms and conditions of Section 21 (Clawback) of the Plan. Without limiting the foregoing sentence, by accepting this Award and the benefits provided hereunder, the Grantee hereby acknowledges and agrees that the Grantee, this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation (including any equity-based awards or cash-based awards) provided to the Grantee shall be subject to the Murphy Oil Corporation Compensation Recoupment Policy (as may be amended from time to time, the "Recoupment Policy") or any other clawback or recoupment arrangements or policies the Company has in place from time to time, in each case, subject to the terms and conditions thereof. Accordingly, the Grantee agrees and acknowledges that this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation provided to the Grantee (as well as any other payments or benefits derived from such amounts, including any Shares issued or cash received upon vesting, exercise or settlement of any such awards or sale of Shares underlying such awards), which may include awards and other incentive-based compensation provided to the Grantee prior to the date of this Agreement, may be subject to forfeiture and/or recoupment in accordance with the terms of the Recoupment Policy or such other applicable clawback or recoupment arrangements or policies.

11. The Plan, this Agreement and the Brochure are administered by the Committee. In the event of any conflict between the terms and provisions of the Plan, this Agreement and/or the Brochure, the terms and provisions of the Plan shall control. The Committee has the full authority and discretion to interpret and administer the Plan consistent with the terms and provisions of the Plan.

Attest: Murphy Oil Corporation

______________________________ By ______________________

MURPHY OIL CORPORATION

TIME-BASED RESTRICTED STOCK UNIT - STOCK SETTLED
GRANT AGREEMENT

Time-Based Restricted Stock Unit Award Number	Name of Grantee	Number of Restricted Stock Units Subject to this Grant
__[[GRANTNUMBER]]	[[FIRSTNAME]] [[MIDDLENAME]] __________[[LASTNAME]]	__[[SHARESGRANTED]]

This Time-Based Restricted Stock Unit Award (the "Award") is granted on and dated [[GRANTDATE]] (the "Grant Date"), by Murphy Oil Corporation, a Delaware corporation (the "Company"), pursuant to and for the purposes of the 2025 Long-Term Incentive Plan (the "Plan"). Any terms used herein and not otherwise defined shall have the meanings set forth in the Plan.

This Agreement is subject to the following terms and provisions:

1. The Company hereby grants to the individual named above (the "Grantee") an Award of Time-Based Restricted Stock Units each equal in value to one share of Common Stock of the Company (collectively, the "Units"). This Award constitutes a right to receive Shares in the future and does not represent any current interest in the Shares subject to the Award.

2. This Award is subject to the following vesting and time lapse restrictions:

(a) In accordance with the Plan, this Award will fully vest and Shares will be issued, less any Shares deducted for applicable withholding taxes, without restrictions, on the third anniversary of the Grant Date (the "Vesting Date"); *provided* that, except as set forth in Sections 2(c), 2(d) and 2(e) below, the Grantee is employed by the Company on the Vesting Date; *provided further*, that this award shall not vest whenever the delivery of Shares under it would be a violation of any applicable law, rule or regulation.

(b) In the event that the Grantee's employment terminates any time prior to the Vesting Date, except as set forth in Sections 2(c), 2(d) and 2(e) below, he/she will forfeit all Units pursuant to this Award.

(c) In the event of the Grantee's termination of employment due to (i) the Grantee's death, disability, or retirement (as determined in accordance with the Plan) or (ii) except if the Grantee is subject to Section 2(e) below, a Reduction in Force (as defined below) prior to the Vesting Date, the Grantee will receive the pro-rata number of Units earned based upon the number of months worked pursuant to this Award up to the date of the Grantee's termination of employment. The Grantee (or his/her beneficiary) will be paid his/her Shares, less any Shares deducted for applicable withholding taxes, as soon as reasonably practicable following the date of the Grantee's termination of employment.

(d) If the Grantee is not an Executive or otherwise a party to a Severance Protection Agreement with the Company at any time during the period beginning on the Grant Date and ending on the date on which a Change in Control occurs, this Award will fully vest and 100 percent of the Time-Based Restricted Stock Units will be deemed to be earned and Shares will be issued, less any Shares deducted for applicable withholding taxes, without restrictions, upon the occurrence of a Change in Control (as such term is defined in the Plan); *provided, however*, that no issuance of Shares will be made until the Vesting Date unless the Change in Control also qualifies as a change in the ownership or effective control of Murphy Oil Corporation, or in the ownership of a substantial portion of its assets, as determined under Section 409A of the Internal Revenue Code.

(e) If the Grantee is an Executive or is otherwise a party to a Severance Protection Agreement with the Company at any time during the period beginning on the Grant Date and ending on the date on which a Change in Control occurs, this Award will fully vest and 100 percent of the Time-Based Restricted Stock Units will be deemed to be earned and Shares will be issued in full, without restriction, as of the date of the Grantee's Qualifying Termination of Employment. "Qualifying Termination of Employment" means the termination of the Grantee's employment within the two-year period immediately following a Change in Control (x) by the Company or any of its affiliates without Cause or (y) by the Grantee for Good Reason. Upon a Qualifying Termination of Employment, Shares will be issued as soon as reasonably practicable following the date of the Qualifying Termination of Employment, less any Shares deducted for applicable withholding taxes.

(f) For purposes of this Award, "Cause" means the occurrence of any of the following:

(i) Any act or omission by the Grantee which constitutes a material willful breach of the Grantee's obligations to the Company or any of its affiliates or the Grantee's continued and willful refusal to substantially perform satisfactorily any duties reasonably required of the Grantee, which results in material injury to the interest or business reputation of the Company or any of its affiliates and which breach, failure or refusal (if susceptible to cure) is not corrected (other than failure to correct by reason of the Grantee's incapacity due to physical or mental illness) within thirty (30) days after written notification thereof to the Grantee by the Company; *provided* that no act or failure to act on the Grantee's part shall be deemed willful unless done or omitted to be done by the Grantee not in good faith and without reasonable belief that the Grantee's action or omission was in the best interest of the Company or its affiliates;

(ii) The Grantee's commission of any dishonest or fraudulent act, which has caused or may reasonably be expected to cause a material injury to the interest or business reputation of the Company or any of its affiliates;

(iii) The Grantee's plea of guilty or *nolo contendere* to or conviction of a felony under the laws of the United States or any state thereof or any other plea or confession of a similar crime in a jurisdiction in which the Company or any of its affiliates conducts business; or

(iv) The Grantee's commission of a fraudulent act or participation in misconduct which leads to a material restatement of the Company's financial statements.

(g) For purposes of this Agreement, "Executive" means the Company's Chief Executive Officer and any other employee with a title of Vice President or above.

(h) For purposes of this Award, "Good Reason" means the occurrence of any of the following:

(i) Any material diminution in the Grantee's title, status, position, the scope of duties assigned, responsibilities or authority, including the assignment to the Grantee of any duties, responsibilities or authority in any manner adverse to the Grantee or inconsistent with the duties, responsibilities and authority assigned to the Grantee prior to a Change in Control;

(ii) Any reduction in the Grantee's base salary, annual target cash bonus opportunity or long-term incentive award opportunity immediately prior to a Change in Control;

(iii) A relocation of more than fifty (50) miles from the location of the Grantee's principal job location or office prior to a Change in Control; or

(iv) Any other action or inaction that constitutes a material breach by the Company or any of its affiliates of any employment or similar agreement pursuant to which the Grantee provides services to the Company or any of its affiliates; provided, that the Grantee provides the Company with a written notice of termination indicating the Grantee's intent to terminate his or her employment for Good Reason within ninety (90) days after the Grantee becoming aware of any circumstances set forth above, that the Grantee provides the Company with at least thirty (30) days following receipt of such notice to remedy such circumstances, and, if the Company fails to remedy such circumstances during such thirty (30) day period, that the Grantee terminates his or her employment no later than sixty (60) days after the end of such thirty (30) day period.

(i) For purposes of this Award, a "Reduction in Force" means an involuntary termination of the Grantee's employment with the Company and its Subsidiaries by the Company or the applicable Subsidiary without cause (as determined by the Committee) due to a reduction in force as specified and implemented by the Company.

3. In consideration of the grant to the Grantee of this Award, the Grantee agrees that, during the period beginning on the date of the termination of the Grantee's employment for any reason, including retirement or any voluntary resignation (the "Termination Date") and ending on the first anniversary of the Termination Date, the Grantee will not, without the Company's express written consent, (i) directly or indirectly solicit, induce or attempt to induce any employees, agents or consultants of the Company or its subsidiaries or affiliates to do anything from which the Grantee is restricted by reason of this Award; (ii) directly or indirectly solicit, induce or aid others to solicit or induce any employees, agents or consultants of the Company or any of its subsidiaries or affiliates to terminate their employment or engagement with the Company or any of its subsidiaries or affiliates and/or to enter into an employment, agency or consultancy relationship with Grantee or any other person or entity with whom Grantee is affiliated; or (iii) own, manage, operate, control, render service to, or participate in the ownership, management, operation or control of any Competitor (as defined below) anywhere in the United States or in any non

U.S. jurisdiction in which the Company is engaged or plans to engage in business as of the Termination Date; *provided, however*, that Grantee will be entitled to own shares of stock of any corporation having a class of equity securities actively traded on a national securities exchange or the Nasdaq Stock Market which represent, in the aggregate, not more than 1% of such corporation's fully-diluted shares. For purposes of this Award, "Competitor" means any company, other entity or association or individual that directly or indirectly is engaged in (i) the business of oil or gas exploration or production or (ii) any other business in which the Company or any of its subsidiaries is engaged as of the Termination Date.

4. In the event of any relevant change in the capitalization of the Company subsequent to the Grant Date and prior to the Award becoming vested, the number of Units subject to the Award will be equitably adjusted pursuant to the Plan to reflect that change.

5. This Award is not assignable except as provided under the Plan in the case of death, and is not subject in whole or in part to attachment, execution or levy of any kind.

6. The Grantee shall have no voting rights with respect to Shares underlying the Units unless and until such Shares are reflected as issued and outstanding shares on the Company's stock ledger.

7. The Grantee shall not be eligible to receive any dividends or other distributions paid with respect to the Award during the Restricted Period. An amount equivalent to these dividends and/or other distributions shall be paid to the Grantee upon the issuance of Shares and payment of the Award. Any such payment (unadjusted for interest) shall be made in whole Shares, valued as of the date that this Award becomes vested, subject to any Shares deducted for applicable withholding taxes.

8. The Grantee hereby acknowledges and agrees that the Grantee and the Award are subject to the terms and conditions of Section 21 (Clawback) of the Plan. Without limiting the foregoing sentence, by accepting this Award and the benefits provided hereunder, the Grantee hereby acknowledges and agrees that the Grantee, this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation (including any equity-based awards or cash-based awards) provided to the Grantee shall be subject to the Murphy Oil Corporation Compensation Recoupment Policy (as may be amended from time to time, the "Recoupment Policy") or any other clawback or recoupment arrangements or policies the Company has in place from time to time, in each case, subject to the terms and conditions thereof. Accordingly, the Grantee agrees and acknowledges that this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation provided to the Grantee (as well as any other payments or benefits derived from such amounts, including any Shares issued or cash received upon vesting, exercise or settlement of any such awards or sale of Shares underlying such awards), which may include awards and other incentive-based compensation provided to the Grantee prior to the date of this Agreement, may be subject to forfeiture and/or recoupment in accordance with the terms of the Recoupment Policy or such other applicable clawback or recoupment arrangements or policies.

9. The Plan and this Agreement are administered by the Executive Compensation Committee of the Board of Directors of Murphy Oil Corporation. In the event of any conflict between the terms and provisions of the Plan and this Agreement, the terms and provisions of the Plan shall control. The Executive Compensation Committee has the full authority to interpret and administer the Plan consistent with the terms and provisions of the plan document.

Attest: Murphy Oil Corporation

______________________________ By ______________________________

MURPHY OIL CORPORATION

TIME-BASED RESTRICTED STOCK UNIT - CASH SETTLED GRANT AGREEMENT

Time-Based Restricted Stock Unit - Cash Award Number	Name of Grantee	Number of Restricted Stock Units Subject to this Grant
[[GRANTNUMBER]]	[[FIRSTNAME]] [[MIDDLENAME]] __________[[LASTNAME]]	__[[UNITS GRANTED]]

This Time-Based Restricted Stock Unit - Cash Settled Award (the "Award") is granted on and dated [[GRANTDATE]] (the "Grant Date"), by Murphy Oil Corporation, a Delaware corporation (the "Company"), pursuant to and for the purposes of the 2025 Long-Term Incentive Plan (the "Plan"), subject to the provisions set forth herein and in the Plan. Any terms used herein and not otherwise defined shall have the meaning set forth in the Plan.

1. The Company hereby grants to the individual named above (the "Grantee") an Award of Time-Based Restricted Stock Units – Cash Settled each equal in value to one share of Common Stock (collectively, the "Units"). This Award will only settle in cash, and no Shares will be issued under this Award at any time.

2. This Award is subject to the following vesting and time lapse restrictions:

(a) In accordance with the Plan, this Award will fully vest on the third anniversary of the Grant Date (the "Vesting Date") and the Grantee will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as of the Vesting Date, less applicable withholding taxes, within the 60-day period following such vesting date; provided that, except as set forth in Section 2(b), 2(c) or 2(d) below, the Grantee is employed by the Company on the Vesting Date. In the event that the Grantee's employment terminates anytime prior to the Vesting Date, except for reasons specified in Section 2(b), 2(c) or 2(d), he/she will forfeit this Award.

(b) Except as set forth in Section 2(c) below, in the event of the Grantee's death or Normal Termination (other than a termination for Cause or when grounds for Cause exist) prior to the Vesting Date, any then outstanding Units pursuant to this Award shall vest on the date of such termination in a pro-rated amount determined by multiplying the number of units granted by a fraction, the numerator of which is the number of months in the period beginning on the Grant Date and ending on the last day of the month in which the Grantee terminates employment, and the denominator of which is the total number of months in the Restricted Period. The Grantee (or his/her beneficiary) will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as of the termination date, less applicable withholding taxes, as soon as reasonably practicable within the 60-day period following the date of the Grantee's termination of employment.

(c) In the event of the Grantee's termination of employment (other than a termination for Cause or when grounds for Cause exist) when the Grantee is (i) Retirement Eligible and (ii) (x) is 60 years or older and has ten (10) or more continuous years of service as an Employee or (y) is 65 years or older and has five (5) or more continuous years of service as an Employee, any then outstanding Units pursuant to this Award shall vest on the date of such termination of employment. The Grantee (or his/her beneficiary) will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as of the termination date, less applicable withholding taxes, as soon as reasonably practicable within the 60-day period following the date of the Grantee's termination of employment. For purposes of this Section 2(c), the Grantee will be credited with one year of service following each full year of employment for purposes of this section; provided, that, any years of service accrued prior to a break in service will not count towards the determination if the break in service was more than twelve (12) months in duration. Partial years of service, including partial years of prior service, will not be recognized and will not count towards such determination of years of service for purposes of this section.

(d) Notwithstanding anything to the contrary herein, this Award will fully vest and one hundred percent (100%) of the Units granted will be deemed to be earned as of the date of the Grantee's Qualifying Termination of Employment. "Qualifying Termination of Employment" means the termination of the Grantee's employment within the two-year period immediately following a Change in Control (x) by the Company or any of its affiliates without Cause or

(y) by the Grantee for Good Reason. The Grantee will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as soon as reasonably practicable within the 60-day period following the date of such termination, less applicable withholding taxes; provided, that the timing of such payment shall comply with Section 409A of the Code.

(e) For purposes of this Award, "Cause" means the occurrence of any of the following:

(i) Any act or omission by the Grantee which constitutes a material willful breach of the Grantee's obligations to the Company or any of its affiliates or the Grantee's continued and willful refusal to substantially perform satisfactorily any duties reasonably required of the Grantee, which results in material injury to the interest or business reputation of the Company or any of its affiliates and which breach, failure or refusal (if susceptible to cure) is not corrected (other than failure to correct by reason of the Grantee's incapacity due to physical or mental illness) within thirty (30) days after written notification thereof to the Grantee by the Company; *provided* that no act or failure to act on the Grantee's part shall be deemed willful unless done or omitted to be done by the Grantee not in good faith and without reasonable belief that the Grantee's action or omission was in the best interest of the Company or its affiliates;

(ii) The Grantee's commission of any dishonest or fraudulent act, which has caused or may reasonably be expected to cause a material injury to the interest or business reputation of the Company or any of its affiliates;

(iii) The Grantee's plea of guilty or *nolo contendere* to or conviction of a felony under the laws of the United States or any state thereof or any other plea or confession of a similar crime in a jurisdiction in which the Company or any of its affiliates conducts business; or

(iv) The Grantee's commission of a fraudulent act or participation in misconduct which leads to a material restatement of the Company's financial statements.

(f) For purposes of this Award, "Good Reason" means the occurrence of any of the following:

(i) Any material diminution in the Grantee's title, status, position, the scope of duties assigned, responsibilities or authority, including the assignment to the Grantee of any duties, responsibilities or authority in any manner adverse to the Grantee or inconsistent with the duties, responsibilities and authority assigned to the Grantee prior to a Change in Control;

(ii) Any reduction in the Grantee's base salary, annual target cash bonus opportunity or long-term incentive award opportunity immediately prior to a Change in Control;

(iii) A relocation of more than fifty (50) miles from the location of the Grantee's principal job location or office prior to a Change in Control; or

(iv) Any other action or inaction that constitutes a material breach by the Company or any of its affiliates of any employment or similar agreement pursuant to which the Grantee provides services to the Company or any of its affiliates;

provided, that the Grantee provides the Company with a written notice of termination indicating the Grantee's intent to terminate his or her employment for Good Reason within ninety (90) days after the Grantee becoming aware of any circumstances set forth above, that the Grantee provides the Company with at least thirty (30) days following receipt of such notice to remedy such circumstances, and, if the Company fails to remedy such circumstances during such thirty (30) day period, that the Grantee terminates his or her employment no later than sixty (60) days after the end of such thirty (30) day period.

3. In the event of any relevant change in the capitalization of the Company subsequent to the Grant Date and prior to the Vesting Date, the number of Units may be equitably adjusted pursuant to the Plan to reflect that change.

4. This Award is not assignable except as provided in the case of death and is not subject in whole or in part to attachment, execution or levy of any kind.

5. The Grantee shall have no voting rights with respect to Shares underlying the Units.

6. The Grantee shall not be eligible to receive any dividends or other distributions paid with respect to these Units during the Restricted Period. An amount equivalent to the cash value of these

dividends and/or other distributions shall be paid to the Grantee upon and subject to the payment of the Award. Any such payment (unadjusted for interest) shall be made in cash, less applicable withholding taxes.

7. The Grantee hereby acknowledges and agrees that the Grantee and the Award are subject to the terms and conditions of Section 21 (Clawback) of the Plan. Without limiting the foregoing sentence, by accepting this Award and the benefits provided hereunder, the Grantee hereby acknowledges and agrees that the Grantee, this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation (including any equity-based awards or cash-based awards) provided to the Grantee shall be subject to the Murphy Oil Corporation Compensation Recoupment Policy (as may be amended from time to time, the "Recoupment Policy") or any other clawback or recoupment arrangements or policies the Company has in place from time to time, in each case, subject to the terms and conditions thereof. Accordingly, the Grantee agrees and acknowledges that this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation provided to the Grantee (as well as any other payments or benefits derived from such amounts, including any Shares issued or cash received upon vesting, exercise or settlement of any such awards or sale of Shares underlying such awards), which may include awards and other incentive-based compensation provided to the Grantee prior to the date of this Agreement, may be subject to forfeiture, cancellation and/or recoupment in accordance with the terms of the Recoupment Policy or such other applicable clawback or recoupment arrangements or policies.

8. Awards granted under the Plan and pursuant to this Agreement are intended to satisfy or be exempt from the requirements of Section 409A of the Code and related regulations and Treasury pronouncements ("Section 409A") to avoid the imposition of any taxes, including additional income taxes, thereunder. In accordance with the terms of the Plan, if the Grantee is deemed to be a "specified employee" under Section 409A at the time of such Grantee's "separation from service" (as defined in Section 409A), and any amount with respect to an Award is "deferred compensation" subject to Section 409A, any distribution of such amount that otherwise would be made to such Grantee with respect to an Award as a result of such "separation from service" shall not be made until the date that is six months after such "separation from service," except to the extent that earlier distribution would not result in such Grantee's incurring interest or additional tax under Section 409A. If the Award is "deferred compensation" subject to Section 409A and provides for payment (or the acceleration of a payment date) upon the disability of the Grantee, such amounts shall only be paid (or such payment date shall only be accelerated) to the extent the Grantee's disability meets the requirements for "disability" within the meaning of Section 1.409A-3(i)(4) of the Treasury Regulations. If the Award includes a "series of installment payments" (within the meaning of Section 1.409A-2(b)(2)(iii) of the Treasury Regulations), the Grantee's right to such series of installment payments shall be treated as a right to a series of separate payments and not as a right to a single payment, and if the Award includes "dividend equivalents" (within the meaning of Section 1.409A-3(e) of the Treasury Regulations), the Grantee's right to such dividend equivalents shall be treated separately from the right to other amounts under the Award. In the case of any Award which is to be paid out when vested and is intended to qualify as an exempt "short term deferral" under Section 409A, such payment shall be made as soon as administratively feasible after the Award became vested, but in no event shall such payment be made later than 2-1/2 months after the end of the calendar year in which the Award became vested unless otherwise permitted under the exemption provisions of Section 409A.

9. The Plan and this Agreement are administered by the Compensation Committee. In the event of any conflict between the terms and provisions of the Plan and this Agreement, the terms and provisions of the Plan shall control. The Compensation Committee has the full authority and discretion to interpret and administer the Plan consistent with the terms and provisions of the Plan.

Attest: Murphy Oil Corporation

______________________________________ By ___________________________________

MURPHY OIL CORPORATION

TIME-BASED RESTRICTED STOCK UNIT - CASH SETTLED GRANT AGREEMENT

Time-Based Restricted Stock Unit - Cash Award Number	Name of Grantee	Number of Restricted Stock Units Subject to this Grant
[[GRANTNUMBER]]	[[FIRSTNAME]] [[MIDDLENAME]] [[LASTNAME]]	[[SHARESGRANTED]]

This Time-Based Restricted Stock Unit - Cash Settled Award (the “Award”) is granted on and dated [[GRANTDATE]] (the “Grant Date”), by Murphy Oil Corporation, a Delaware corporation (the “Company”), pursuant to and for the purposes of the 2025 Long-Term Incentive Plan (the “Plan”), subject to the provisions set forth herein and in the Plan. Any terms used herein and not otherwise defined shall have the meaning set forth in the Plan.

1. The Company hereby grants to the individual named above (the “Grantee”) an Award of Time-Based Restricted Stock Units – Cash Settled each equal in value to one share of Common Stock (collectively, the “Units”). This Award will only settle in cash and no Shares will be issuable under this Award.

2. This Award is subject to the following vesting and time lapse restrictions:

(a) In accordance with the Plan, this Award will fully vest on the third anniversary of the Grant Date (the “Vesting Date”) and the Grantee will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as of the Vesting Date, less applicable withholding taxes, within the 60-day period following such vesting date; provided that, except as set forth in Section 2(b), 2(c) or 2(d) below, the Grantee is employed by the Company on the Vesting Date. In the event that the Grantee’s employment terminates any time prior to the Vesting Date, except for reason of specified in Section 2(b), 2(c) or 2(d) below, he/she will forfeit this Award.

(b) Except as set forth in Section 2(c) below, in the event of the Grantee’s death or Normal Termination (other than a termination for Cause or when grounds for Cause exist) or (ii) a Reduction in Force (as defined below) prior to the Vesting Date, any then outstanding Units pursuant to this Award shall vest on the date of such termination of employment in a pro-rated amount determined by multiplying the number of Units granted by a fraction, the numerator of which is the number of months in the period beginning on the Grant Date and ending on the last day of the month in which the Grantee’s employment is terminated, and the denominator of which is the total number of months in the Restricted Period. The Grantee (or his/her beneficiary) will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as of the termination date, less applicable withholding taxes, as soon as reasonably practicable within the 60-day period following the date of the Grantee’s termination of employment.

(c) In the event of the Grantee’s termination of employment (other than a termination for Cause or when grounds for Cause exist) when the Grantee is (i) Retirement Eligible and (ii) (x) is 60 years or older and has ten (10) or more continuous years of service as an Employee or (y) is 65 years or older and has five (5) or more continuous years of service as an Employee, any then outstanding Units pursuant to this Award shall vest on the date of such termination of employment. The Grantee (or his/her beneficiary) will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as of the termination date, less applicable withholding taxes, as soon as reasonably practicable within the 60-day period following the date of the Grantee’s termination of employment. For purposes of this Section 2(c), the Grantee will be credited with one year of service following each full year of employment; provided, that, any years of service accrued prior to a break in service will not count towards the determination if the break in service was more than twelve (12) months in duration. Partial years of service, including partial years of prior service, will not be recognized and will not count towards such determination of years of service for purposes of this section.

(d) Notwithstanding anything to the contrary herein, this Award will fully vest and one hundred percent (100%) of the Units granted will be deemed to be earned as of the date of the Grantee’s Qualifying Termination of Employment. “Qualifying Termination of Employment” means the termination of the Grantee’s employment within the two-year period immediately following a Change in Control (x) by the Company or any of its affiliates without Cause or (y) by the Grantee for Good Reason. The Grantee will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as soon as reasonably practicable within the 60-day period following the date of such termination, less applicable withholding taxes; provided, that the timing of such payment shall comply with Section 409A of the Code.

(e) For purposes of this Award, a "Reduction in Force" means an involuntary termination of the Grantee's employment with the Company and its Subsidiaries by the Company or the applicable Subsidiary without cause (as determined by the Committee) due to a reduction in force as specified and implemented by the Company.

(f) For purposes of this Award, "Cause" means the occurrence of any of the following:

(i) Any act or omission by the Grantee which constitutes a material willful breach of the Grantee's obligations to the Company or any of its affiliates or the Grantee's continued and willful refusal to substantially perform satisfactorily any duties reasonably required of the Grantee, which results in material injury to the interest or business reputation of the Company or any of its affiliates and which breach, failure or refusal (if susceptible to cure) is not corrected (other than failure to correct by reason of the Grantee's incapacity due to physical or mental illness) within thirty (30) days after written notification thereof to the Grantee by the Company; *provided* that no act or failure to act on the Grantee's part shall be deemed willful unless done or omitted to be done by the Grantee not in good faith and without reasonable belief that the Grantee's action or omission was in the best interest of the Company or its affiliates;

(ii) The Grantee's commission of any dishonest or fraudulent act, which has caused or may reasonably be expected to cause a material injury to the interest or business reputation of the Company or any of its affiliates;

(iii) The Grantee's plea of guilty or *nolo contendere* to or conviction of a felony under the laws of the United States or any state thereof or any other plea or confession of a similar crime in a jurisdiction in which the Company or any of its affiliates conducts business; or

(iv) The Grantee's commission of a fraudulent act or participation in misconduct which leads to a material restatement of the Company's financial statements.

(g) For purposes of this Award, "Good Reason" means the occurrence of any of the following:

(i) Any material diminution in the Grantee's title, status, position, the scope of duties assigned, responsibilities or authority, including the assignment to the Grantee of any duties, responsibilities or authority in any manner adverse to the Grantee or inconsistent with the duties, responsibilities and authority assigned to the Grantee prior to a Change in Control;

(ii) Any reduction in the Grantee's base salary, annual target cash bonus opportunity or long-term incentive award opportunity immediately prior to a Change in Control;

(iii) A relocation of more than fifty (50) miles from the location of the Grantee's principal job location or office prior to a Change in Control; or

(iv) Any other action or inaction that constitutes a material breach by the Company or any of its affiliates of any employment or similar agreement pursuant to which the Grantee provides services to the Company or any of its affiliates;

provided, that the Grantee provides the Company with a written notice of termination indicating the Grantee's intent to terminate his or her employment for Good Reason within ninety (90) days after the Grantee becoming aware of any circumstances set forth above, that the Grantee provides the Company with at least thirty (30) days following receipt of such notice to remedy such circumstances, and, if the Company fails to remedy such circumstances during such thirty (30) day period, that the Grantee terminates his or her employment no later than sixty (60) days after the end of such thirty (30) day period.

3. In the event of any relevant change in the capitalization of the Company subsequent to the Grant Date and prior to the Vesting Date, the number of Units may be equitably adjusted pursuant to the Plan to reflect that change.

4. This Award is not assignable except as provided in the case of death and is not subject in whole or in part to attachment, execution or levy of any kind.

5. The Grantee shall have no voting rights with respect to Shares underlying the Units.

6. The Grantee shall not be eligible to receive any dividends or other distributions paid with respect to these Units during the Restricted Period. An amount equivalent to the cash value of these dividends and/or other distributions shall be paid to the Grantee upon and subject to the payment of the Award. Any such payment (unadjusted for interest) shall be made in cash, less applicable withholding taxes.

7. The Grantee hereby acknowledges and agrees that the Grantee and the Award are subject to the terms and conditions of Section 21 (Clawback) of the Plan. Without limiting the foregoing sentence, by accepting this Award and the benefits provided hereunder, the Grantee hereby acknowledges and agrees that the Grantee, this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation (including any equity-based awards or cash-based awards) provided to the Grantee shall be subject to the Murphy Oil Corporation Compensation Recoupment Policy (as may be amended from time to time, the "Recoupment Policy") or any other clawback or recoupment arrangements or policies the Company has in place from time to time, in each case, subject to the terms and conditions thereof. Accordingly, the Grantee agrees and acknowledges that this Award, any other award granted to the Grantee under the Plan and any other incentive-based compensation provided to the Grantee (as well as any other payments or benefits derived from such amounts, including any Shares issued or cash received upon vesting, exercise or settlement of any such awards or sale of Shares underlying such awards), which may include awards and other incentive-based compensation provided to the Grantee prior to the date of this Agreement, may be subject to forfeiture, cancellation and/or recoupment in accordance with the terms of the Recoupment Policy or such other applicable clawback or recoupment arrangements or policies.

8. Awards granted under the Plan and pursuant to this Agreement are intended to satisfy or be exempt from the requirements of Section 409A of the Code and related regulations and Treasury pronouncements ("Section 409A") to avoid the imposition of any taxes, including additional income taxes, thereunder. In accordance with the terms of the Plan, if the Grantee is deemed to be a "specified employee" under Section 409A at the time of such Grantee's "separation from service" (as defined in Section 409A), and any amount with respect to an Award is "deferred compensation" subject to Section 409A, any distribution of such amount that otherwise would be made to such Grantee with respect to an Award as a result of such "separation from service" shall not be made until the date that is six months after such "separation from service," except to the extent that earlier distribution would not result in such Grantee's incurring interest or additional tax under Section 409A. If the Award is "deferred compensation" subject to Section 409A and provides for payment (or the acceleration of a payment date) upon the disability of the Grantee, such amounts shall only be paid (or such payment date shall only be accelerated) to the extent the Grantee's disability meets the requirements for "disability" within the meaning of Section 1.409A-3(i)(4) of the Treasury Regulations. If the Award includes a "series of installment payments" (within the meaning of Section 1.409A-2(b)(2)(iii) of the Treasury Regulations), the Grantee's right to such series of installment payments shall be treated as a right to a series of separate payments and not as a right to a single payment, and if the Award includes "dividend equivalents" (within the meaning of Section 1.409A-3(e) of the Treasury Regulations), the Grantee's right to such dividend equivalents shall be treated separately from the right to other amounts under the Award. In the case of any Award which is to be paid out when vested and is intended to qualify as an exempt "short term deferral" under Section 409A, such payment shall be made as soon as administratively feasible after the Award became vested, but in no event shall such payment be made later than 2-1/2 months after the end of the calendar year in which the Award became vested unless otherwise permitted under the exemption provisions of Section 409A.

9. The Plan and this Agreement are administered by the Compensation Committee. In the event of any conflict between the terms and provisions of the Plan and this Agreement, the terms and provisions of the Plan shall control. The Compensation Committee has the full authority and discretion to interpret and administer the Plan consistent with the terms and provisions of the Plan.

Attest: Murphy Oil Corporation

______________________________ By ______________________________

MURPHY OIL CORPORATION
SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2025

Name of Company		State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT)			
A. Arkansas Oil Company		Delaware	100.00
B. Caledonia Land Company		Delaware	100.00
C. El Dorado Engineering Inc.		Delaware	100.00
a. El Dorado Contractors		Delaware	100.00
b. El Dorado Exploracion y Produccion, S. de. R.L. de C.V. (see company F.b.ii.1. below)		Mexico	10.00
D. Marine Land Company		Delaware	100.00
E. Murphy Eastern Oil Company		Delaware	100.00
F. Murphy Exploration & Production Company		Delaware	100.00
a. Murphy Building Corporation		Delaware	100.00
b. Murphy Exploration & Production Company - International		Delaware	100.00
i. Canam Offshore LLC		Delaware	100.00
1. Canam Brunei Oil Ltd.		Bahamas	100.00
2. Canam Offshore Limited		Bahamas	100.00
3. Murphy Peninsular Malaysia Oil Co., Ltd.		Bahamas	100.00
4. Murphy Cuu Long Tay Oil Co., Ltd.		Bahamas	100.00
a. Murphy Netherlands Holdings B.V.	Murphy Netherlands Holdings B.V.	Netherlands	100.00
i. Murphy Sur, S. de R. L. de C.V. (see company F.b.i.4.a.ii.1. below)		Mexico	0.01
ii. Murphy Netherlands Holdings II B.V.		Netherlands	100.00
1. Murphy Sur, S. de R. L. de C.V.		Mexico	99.99
ii. El Dorado Exploration, S.A.		Delaware	100.00
1. El Dorado Exploracion y Produccion, S. de. R.L. de C.V.		Mexico	90.00
iii. Murphy Asia Oil Co., Ltd.		Bahamas	100.00
iv. Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda. (see company F.b.xix.1. below)		Brazil	90.00
v. Murphy CI-102 Oil Co., Ltd.		Bahamas	100.00
vi. Murphy CI-103 Oil Co., Ltd.		Bahamas	100.00
vii. Murphy CI-502 Oil Co., Ltd.		Bahamas	100.00
viii. Murphy CI-531 Oil Co., Ltd.		Bahamas	100.00
ix. Murphy CI-709 Oil Co., Ltd.		Bahamas	100.00
x. Murphy CI-807 Oil Co., Ltd.		Bahamas	100.00
xi. Murphy Cuu Long Bac Oil Co., Ltd.		Bahamas	100.00
xii. Murphy Dai Nam Oil Co., Ltd.		Bahamas	100.00
xiii. Murphy Equatorial Guinea Oil Co., Ltd.		Bahamas	100.00
xiv. Murphy Exploration Holdings, LLC		Delaware	100.00
1. Murphy Australia Oil Pty. Ltd.		Western Australia	100.00
a. Murphy Australia AC/P 36 Oil Pty. Limited		Western Australia	100.00
2. Murphy Australia AC/P 58 Oil Pty. Ltd.		Western Australia	100.00
3. Murphy Australia WA-481-P Oil Pty. Ltd.		Western Australia	100.00

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
xv. Murphy Luderitz Oil Co., Ltd.	Bahamas	100.00
xvi. Murphy Morocco Oil Co., Ltd.	Bahamas	100.00
xvii. Murphy Nha Trang Oil Co., Ltd.	Bahamas	100.00
xviii. Murphy Offshore Oil Co. Ltd.	Bahamas	100.00
xix. Murphy Overseas Ventures Inc.	Delaware	100.00
1. Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda.	Brazil	10.00
xx. Murphy Phuong Nam Oil Co., Ltd.	Bahamas	100.00
xxi. Murphy-Spain Oil Company	Delaware	100.00
xxii. Murphy West Africa, Ltd.	Bahamas	100.00
xxiii. Murphy Worldwide, Inc.	Delaware	100.00
c. Murphy Exploration & Production Company - USA	Delaware	100.00
i. MP Gulf of Mexico, LLC	Delaware	80.00
ii. Medusa Spar LLC	Delaware	40.00
G. Murphy Oil Company Ltd.	Canada	100.00
H. New Murphy Oil (UK) Corporation	Delaware	100.00
a. Murphy Petroleum Limited	England	100.00
i. Murco Petroleum Limited	England	100.00

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statements (No. 333-282615, 333-256048, 333-241837, 333-288984, and 333-226494) on Form S-8 and in the registration statement (No. 333-282655) on Form S-3 of our reports dated February 25, 2026, with respect to the consolidated financial statements of Murphy Oil Corporation and subsidiaries and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 25, 2026

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the incorporation by reference in the Registration Statement (File Nos. 333-282615, 333-256048 and 333-241837) on Form S-8, the Registration Statement (File No. 333-282655) on Form S-3 of Murphy Oil Corporation, and of the reference to our reports regarding certain offshore and onshore assets in the United States effective December 31, 2025 and dated January 26, 2026 for Murphy Oil Corporation, which appears in the December 31, 2025 annual report on Form 10-K of Murphy Oil Corporation, including any reference to our firm under the heading “Experts”.

/s/ RYDER SCOTT COMPANY, L.P.

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

Houston, Texas
February 24, 2026

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

McDANIEL

CONSENT OF MCDANIEL & ASSOCIATES CONSULTANTS LTD.

We hereby consent to the reference of our firm and to the use of our report conducting an audit of the Canadian Oil and Gas Properties for the Kaybob Duvernay and Greater Tupper Montney Projects located within the Province of British Columbia and Alberta, Canada, effective December 31, 2025 and dated January 19, 2026 in the Murphy Oil Corporation Form 10-K for the year ended December 31, 2025, Registration Statement Form S-8, No. 333-282615, 333-256048 and 333-241837 and Registration Statement Form S-3, No. 333-282655 and in any related prospectus, including any reference to our firm under the heading “Experts” in such prospectus.

McDaniel & Associates Consultants Ltd.

/s/ Michael Verney

Michael Verney, P.Eng.
Executive Vice President

February 24, 2026
APEGA PERMIT NUMBER: P3145

Exhibit 23.4

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference in the Registration Statement (File Nos. 333-282615, 333-256048 and 333-241837) on Form S-8 and the Registration Statement (File No. 333-282655) on Form S-3 of Murphy Oil Corporation, as well as to the reference in the December 31, 2025, annual report on Form 10-K of Murphy Oil Corporation, of our report regarding certain assets in the United States located in federal waters in the Gulf of America, effective December 31, 2025, and dated February 4, 2026, including any reference to our firm under the heading “Experts”.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

Houston, Texas
February 23, 2026

Exhibit 23.5

CONSENT OF GLJ LTD.

Jeffery Wilson
General Manager - Corporate Reserves
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

We hereby consent to the reference of our firm and to the use of our report conducting an audit of the Canadian Oil and Gas Properties for the Hibernia and Terra Nova oil properties located offshore in Newfoundland, Canada, effective December 31, 2025 and dated January 27, 2026 in the Murphy Oil Corporation Form 10-K for the year ended December 31, 2025, Registration Statement Form S-8, No. 333-282615, 333-256048 and 333-241837 and Registration Statement Form S-3, No. 333-282655 and in any related prospectus, including any reference to our firm under the heading "Experts" in such prospectus.

Sincerely,

GLJ LTD.

/s/ Patrick A. Olenick
Patrick A. Olenick, P.Eng.
Senior Vice President

Dated: February 24, 2026
Calgary, Alberta
APEGA Permit Number: 67686

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Eric M. Hambly, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal controls over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions)

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls over financial reporting.

Date: February 25, 2026

/s/ Eric M. Hambly
Eric M. Hambly
Principal Executive Officer

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Thomas J. Mireles, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal controls over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls over financial reporting.

Date: February 25, 2026

/s/ Thomas J. Mireles
Thomas J. Mireles
Principal Financial Officer

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Murphy Oil Corporation (the “Company”) on Form 10-K for the year ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Eric M. Hambly and Thomas J. Mireles, Principal Executive Officer and Principal Financial Officer, respectively, of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 25, 2026

/s/ Eric M. Hambly
Eric M. Hambly
Principal Executive Officer

/s/ Thomas J. Mireles
Thomas J. Mireles
Principal Financial Officer

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to the 100%

Leasehold Interests of the

Murphy Petrobras GOM JV

SEC Parameters

As of

December 31, 2025

Eric T. Nelson, P.E.
TBPELS License No. 102286
Executive Vice President

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

STATE OF TEXAS
ERIC T. NELSON
102286
LICENSED
PROFESSIONAL ENGINEER

January 26, 2026

Jeffrey Wilson
General Manager - Corporate Reserves
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Dear Mr. Wilson:

At the request of Murphy Oil Corporation (Murphy), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2025 prepared by Murphy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 10, 2026 and presented herein, was prepared for public disclosure by Murphy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. For the Gulf of America properties, the estimated reserves shown herein represent the Murphy and Petrobras GOM JV (MPGOM) estimated net reserves attributable to Murphy's leasehold interests in certain properties owned by MPGOM. The properties reviewed by Ryder Scott incorporate Murphy's reserves determinations and are located in federal waters offshore Louisiana and Alabama.

The properties reviewed by Ryder Scott account for a portion of Murphy's total net proved reserves as of December 31, 2025. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott in this report addresses 10.4 percent of the total proved net reserves of Murphy on a barrel of oil equivalent, BOE basis as of December 31, 2025. At Murphy's request, this report presents the net reserves attributable to the 100% interests of the MPGOM, which includes the non-controlling interest of Petrobras.

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

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Murphy has informed us that in the preparation of their reserves and income projections, as of December 31, 2025, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Murphy attributable to Murphy's interest and entitlement in properties that we reviewed are summarized below. The net reserves below represent 100 percent of the Murphy and Petrobras GOM JV (MPGOM) and include the non-controlling interest of Petrobras:

SEC PARAMETERS
Estimated Net Reserves
Attributable to the 100 Percent Leasehold Interests of the
Murphy Petrobras GOM JV (MPGOM)
As of December 31, 2025

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves to MPGOM			
Oil/Condensate – Mbbl	60,821	9,523	70,344
Plant Products – Mbbl	1,872	162	2,034
Gas – MMcf*	20,474	1,750	22,224
MBOE	66,106	9,976	76,082

**Includes fuel gas.*

SEC PARAMETERS
Estimated Net Reserves
Attributable to Murphy's Leasehold Interests in the
Murphy Petrobras GOM JV (MPGOM)
As of December 31, 2025

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves to Murphy			
Oil/Condensate – Mbbl	48,765	7,697	56,462
Plant Products – Mbbl	1,509	132	1,641
Gas – MMcf*	16,609	1,467	18,076
MBOE	53,041	8,075	61,116

**Includes fuel gas.*
Values may not sum to total due to rounding.

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the area in which the gas reserves are located. Certain gas volumes that are consumed as fuel in operations are also included as net gas reserves; these volumes represent 7,135 MMcf at Murphy's leasehold interests of MPGOM, or 1.9 percent of Murphy's net MBOE. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent.

Reserves Included in This Report

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

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

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

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

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

Audit Data, Methodology, Procedure and Assumptions

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

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

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

The reserves, prepared by Murphy, for the properties that we reviewed were estimated by performance methods or the volumetric method. The proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were primarily estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through October 2025, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Murphy or obtained from public data sources and were considered sufficient for the purpose thereof. Certain proved producing reserves that we reviewed were estimated by the volumetric method. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

Most of the reserves prepared by Murphy attributable to the non-producing and the undeveloped status categories that we reviewed were estimated by performance methods, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Murphy for our review or which we have obtained from public data sources that were available through

November 2025. The data utilized from the analogues in conjunction with well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

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

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

The hydrocarbon prices furnished by Murphy for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2025 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The following table summarizes the "benchmark prices" and "price reference" used by Murphy for the geographic area reviewed by us. For certain properties, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used by Murphy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as "differentials." The differentials used by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices	Average Realized Prices*
North America					
United States – Offshore	Oil/Condensate	WTI Cushing	$65.34/Bbl	$65.54/Bbl	$65.54/Bbl
	NGLs	WTI Cushing	$65.34/Bbl	$18.92/Bbl	$18.92/Bbl
	Gas	Henry Hub	$3.387/MMBTU	$2.28/Mcf	$3.79/Mcf

**Realized prices excluding fuel gas volumes, as previously noted.*

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

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed.

Operating costs furnished by Murphy are based on the operating expense reports of Murphy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose; information provided included historic operating expenses, pay out balances, and royalty relief information. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Murphy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs were provided by Murphy. Murphy's estimates of the net abandonment costs were accepted without independent verification. We have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by Murphy and included herein.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Murphy's plans to develop these reserves as of December 31, 2025. The implementation of Murphy's development plans as presented to us is subject to the approval process adopted by Murphy's management. As the result of our inquiries during the course of our review, Murphy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Murphy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Murphy. Murphy has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Murphy has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2025, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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

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

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

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

Murphy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

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

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

Murphy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Murphy's forecast of future proved production, we have relied upon data furnished by Murphy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. The data furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose. We consider the factual data furnished to us by Murphy to be appropriate and sufficient for the purpose of our review of Murphy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Murphy and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Murphy in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

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

Standards of Independence and Professional Qualification

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

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

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

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

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

Terms of Usage

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

Murphy Oil Corporation makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Murphy Oil Corporation has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 (File No. 333-260287) and Form S-8 (File Nos. 333-256048 and 333-241837) of Murphy Oil Corporation of the references to our name, as well as to the references to our report for Murphy Oil Corporation, which appears in the December 31, 2025 annual report on Form 10-K of Murphy Oil Corporation. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Murphy Oil Corporation.

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

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

Very truly yours,

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

Eric T. Nelson, P.E.
TBPELS License No. 102286
Executive Vice President

STATE OF TEXAS
ERIC T. NELSON
102286
LICENSED
PROFESSIONAL ENGINEER

ETN (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is an Executive Vice President and a member of the Board of Directors. He is responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Nelson served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Nelson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Nelson earned a Bachelor of Science degree in Chemical Engineering from the University of Tulsa in 2002 (summa cum laude) and a Master of Business Administration from the University of Texas in 2007 (Dean's Award). He is a licensed Professional Engineer in the State of Texas. Mr. Nelson is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Nelson fulfills. As part of his 2025 continuing education hours, Mr. Nelson attended over 20 hours of training during 2025 covering such topics as CCUS, evaluations of resource play reserves, evaluation of simulation models, procedures and software, and ethics training.

Based on his educational background, professional training and more than 19 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Nelson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

PREAMBLE

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

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

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

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

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

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

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

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

RESERVES (SEC DEFINITIONS)

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

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

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the

lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

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

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

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

Shut-In
Shut-in Reserves are expected to be recovered from:
- *(1) completion intervals that are open at the time of the estimate but which have not yet started producing;*
- *(2) wells which were shut-in for market conditions or pipeline connections; or*
- *(3) wells not capable of production for mechanical reasons.*

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

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

UNDEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

EFS Operated

SEC Parameters

As of

December 31, 2025

Eric T. Nelson, P.E.
TBPELS License No. 102286
Executive Vice President

STATE OF TEXAS
ERIC T. NELSON
102286
LICENSED
PROFESSIONAL ENGINEER

Tomas Konsen, P.E.
TBPELS License No. 154445
Vice President

STATE OF TEXAS
TOMAS KONSEN
154445
LICENSED
PROFESSIONAL ENGINEER

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

January 26, 2026

Jeffrey Wilson
General Manager - Corporate Reserves
Murphy Oil Corporation
9805 Katy Freeway, Suite G-200
Houston, TX 77024

Dear Mr. Wilson:

At the request of Murphy Oil Corporation (Murphy), Ryder Scott Company, L.P. (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2025 prepared by Murphy's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our reserves audit, completed on January 10, 2026 and presented herein, was prepared for public disclosure by Murphy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. For the Murphy EFS Operated properties, the estimated reserves shown herein represent Murphy's estimated net reserves attributable to the leasehold interests in certain properties owned by Murphy and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2025. The properties reviewed by Ryder Scott incorporate Murphy's reserves determinations and are located onshore in the state of Texas.

The EFS Operated properties reviewed by Ryder Scott account for a portion of Murphy's total net proved reserves as of December 31, 2025. Based on the estimates of total net proved reserves prepared by Murphy, the Murphy EFS Operated reserves audit conducted by Ryder Scott in this report addresses 21.6 percent of the total proved net reserves of Murphy on a barrel of oil equivalent, BOE basis as of December 31, 2025.

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

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are, in the aggregate and within each geographic area, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. Murphy has informed us that in the preparation of their reserves and income projections, as of December 31, 2025, they used average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by Murphy attributable to Murphy's interest and entitlement in properties that we reviewed are summarized by geographic area as follows.

SEC PARAMETERS
Estimated Net Reserves
Certain Leasehold Interests
Murphy Oil Corporation – EFS Operated
As of December 31, 2025

	Proved		
	Developed	Undeveloped	Total Proved
Audited by Ryder Scott			
Net Reserves			
Oil/Condensate – Mbbl	57,837	46,788	104,625
Plant Products – Mbbl	13,037	11,196	24,233
Gas – MMcf*	100,065	72,673	172,738
MBOE	87,552	70,096	157,648

**Includes fuel gas.*
Values may not sum to total due to rounding.

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. Certain gas volumes that are consumed as fuel in operations are also included as net gas reserves; these volumes represent 42,449 MMcf, or 4.5 percent of the total EFS Operated net MBOE. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousand barrels of oil equivalent.

Reserves Included in This Report

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

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

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

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

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

Audit Data, Methodology, Procedure and Assumptions

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

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

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

The reserves prepared by Murphy for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. The proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were primarily estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through November 2025, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Murphy or obtained from public data sources and were considered sufficient for the purpose thereof. Certain proved producing reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

Most of the reserves prepared by Murphy attributable to the non-producing and the undeveloped status categories that we reviewed were estimated by performance methods, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data, reports and other data furnished to Ryder Scott by Murphy for our review or which we have obtained from public data sources that were available through November 2025. The data utilized from the analogues in conjunction with well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

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

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

The hydrocarbon prices furnished by Murphy for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements.

The initial SEC hydrocarbon benchmark prices in effect on December 31, 2025 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The following table summarizes the "benchmark prices" and "price reference" used by Murphy for the geographic areas reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used by Murphy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as "differentials." The differentials used by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices	Average Realized Prices*
North America					
United States – Onshore	Oil/Condensate	WTI Cushing	$65.34/Bbl	$64.79/BBL	$64.79/BBL
	NGLs	WTI Cushing	$65.34/Bbl	$22.29/BBL	$22.29/BBL
	Gas	Henry Hub	$3.387/MMBTU	$2.16/MCF	$2.87/MCF

**Realized prices excluding fuel gas volumes, as previously noted.*

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

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserves estimates reviewed.

Operating costs furnished by Murphy are based on the operating expense reports of Murphy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose; information provided included historic operating expenses, pay out balances, and royalty relief information. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by Murphy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs were provided by Murphy. Murphy's estimates of the net abandonment costs were accepted without independent verification. We have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by Murphy and included herein.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with Murphy's plans to develop these reserves as of December 31, 2025. The implementation of Murphy's development plans as presented to us is subject to the approval process adopted by Murphy's management. As the result of our inquiries during the course of our review, Murphy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by Murphy's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Murphy. Murphy has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Murphy has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2025, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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

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

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

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

Murphy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

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

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

Murphy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of Murphy's forecast of future proved production, we have relied upon data furnished by Murphy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. The data furnished by Murphy were reviewed by us for their reasonableness using information furnished by Murphy for this purpose. We consider the factual data furnished to us by Murphy to be appropriate and sufficient for the purpose of our review of Murphy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by Murphy and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by Murphy, it is our opinion that the overall procedures and methodologies utilized by Murphy in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Murphy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Murphy in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

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

Standards of Independence and Professional Qualification

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

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

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

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

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

Terms of Usage

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

Murphy Oil Corporation makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Murphy Oil Corporation has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 (File No. 333-260287) and Form S-8 (File Nos. 333-256048 and 333-241837) of Murphy Oil Corporation of the references to our name, as well as to the references to our report for Murphy Oil Corporation, which appears in the December 31, 2025 annual report on Form 10-K of Murphy Oil Corporation. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Murphy Oil Corporation.

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

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

Very truly yours,

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

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PROFESSIONAL ENGINEER

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Tomas Konsen, P.E.
TBPELS License No. 154445
Vice President

ETN-TK (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is an Executive Vice President and a member of the Board of Directors. He is responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Nelson served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Nelson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Nelson earned a Bachelor of Science degree in Chemical Engineering from the University of Tulsa in 2002 (summa cum laude) and a Master of Business Administration from the University of Texas in 2007 (Dean's Award). He is a licensed Professional Engineer in the State of Texas. Mr. Nelson is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Nelson fulfills. As part of his 2024 continuing education hours, Mr. Nelson attended over 20 hours of training during 2024 covering such topics as CCUS, evaluations of resource play reserves, evaluation of simulation models, procedures and software, and ethics training.

Based on his educational background, professional training and more than 19 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Nelson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

PREAMBLE

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

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

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

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

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

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

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

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

RESERVES (SEC DEFINITIONS)

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

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

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the

lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

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

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

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

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

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

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

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

UNDEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

Exhibit 99.3

MCDANIEL

January 19, 2026

Murphy Oil Corporation
9805 Katy Freeway
Suite G-200
Houston, Texas
USA 77024

Attention: Mr. Jeffrey Wilson, General Manager – Corporate Reserves

Reference: **Murphy Oil Corporation**
Evaluation of the Canadian Oil and Gas Properties as of December 31, 2025

Dear Sir:

Pursuant to your request, McDaniel & Associates Consultants Ltd. ("McDaniel") has conducted an independent audit of Murphy Oil Corporation's ("Murphy") proved crude oil, natural gas and natural gas liquids reserves for Murphy's interests in the Kaybob Duvernay and Greater Tupper Montney Projects located within the Provinces of Alberta and British Columbia, Canada. Murphy holds a 99.94 percent working interest in the Greater Tupper Montney Project, a 70.00 percent working interest in the Kaybob Duvernay Project. Murphy has represented that these properties account for approximately 55.3 percent of its total company proved reserves on an equivalent barrel basis (Mboe) as of December 31, 2025, and that its reserves estimates have been prepared in accordance with the United States Securities and Exchange Commission (SEC) definitions. We have reviewed information provided to us by Murphy that it represents to be its estimates of the reserves, as of December 31, 2025, for the same properties as those which we audited. The completion date of our report is January 30, 2026. This report was prepared in accordance with guidelines specified in Item 1202(a)(8) of Regulation S-K and is to be used for inclusion in certain filings of the SEC.

Reserves included herein are expressed as reserves as represented by Murphy. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2025. Working interest reserves are defined as that portion of the gross reserves attributable to the interests owned by Murphy after deducting all working interests owned by others. Net reserves are defined as working interest reserves after the deduction of royalties. Estimates of crude oil, natural gas and natural gas liquids reserves should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information, which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with Murphy personnel, Murphy files, from records on file with the appropriate regulatory agencies and from public sources. In the preparation of this report, we have relied upon such information furnished by Murphy with respect to property interests, production from such properties, current costs of operation and development, prices for production, agreements relating to current and future operations and sale of production as well as various other information and data that were accepted as represented. Furthermore, if in the course of our examination something came to our attention, which brought into question the validity or sufficiency of any of such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

The process of estimating reserves requires complex judgments and decision-making based on available geological, geophysical, engineering and economic data. To estimate the economically recoverable oil, synthetic crude oil and natural gas reserves, and related future net cash flows, we consider many factors and make assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs

Estimates of reserves were prepared using standard geological and engineering methods generally accepted by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 2019)." Generally accepted methods for estimating reserves include volumetric calculations, material balance techniques, production decline curves, pressure transient analysis, analogy with similar reservoirs and reservoir simulation. The method or combination of methods used is based on professional judgment and experience.

Discovered oil and natural gas reserves are generally only produced when they are economically recoverable. As such, oil and gas prices, and capital and operating costs have an impact on whether reserves will ultimately be produced. As required by SEC rules, reserves represent the quantities that are expected to be economically recoverable using existing prices and costs. Estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The proved reserves estimates in this report were based upon 2025 first-of-the-month fiscal average pricing using benchmark pricing supplied by Murphy. Oil prices were based upon West Texas Intermediate at Cushing crude oil benchmark of

USD$65.34 per barrel. Specific pricing for each field was adjusted for historical quality and transportation cost differentials and for currency exchange rates. For total proved reserves in the Greater Tupper Montney Project, the estimated realized prices were CAD$2.47 per Mcf of natural gas including fuel volumes (CAD$2.50 per Mcf excluding fuel volumes) and CAD$88.71 per barrel of natural gas liquids. For total proved reserves in the Kaybob Duvernay Project, the estimated realized prices were CAD$2.70 per Mcf of natural gas including fuel volumes (CAD$2.76 per Mcf excluding fuel volumes), CAD$82.72 per barrel of oil and CAD$39.75 per barrel of natural gas liquids.

Generally, operations are subject to various levels of government controls and regulations. These laws and regulations may include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and additional legislation or amendments that will affect reserves or when any such proposals, if enacted, might become effective generally cannot be predicted. Changes in government regulations could affect reserves or related economics. In the regions that are currently being evaluated, we believe we have applied existing regulations appropriately.

Murphy Estimates

Murphy has represented that estimated proved reserves attributable to the audited properties are based on SEC definitions. These reserves are as follows, expressed in thousands of barrels (Mbbl) and thousands of barrels of oil equivalent (Mboe):

Murphy's estimate of Reserves as of December 31, 2025
Certain Canadian Fields Audited by McDaniel & Associates

Business Unit	Crude Oil (Mboe)	Natural Gas (Mboe)	Natural Gas Liquids (Mboe)	Oil Equivalent (Mboe)
Working Interest Reserves (After Royalties)				
Proved Developed (PD)				
Kaybob Duvernay	7,338	3,789	1,737	12,864
Tupper Montney	-	191,186	669	191,855
Proved Undeveloped (PUD)				
Kaybob Duvernay	11,557	3,590	1,838	16,985
Tupper Montney	-	181,484	607	182,091
Total Proved (TP)				
Kaybob Duvernay	18,895	7,379	3,575	29,849
Tupper Montney	-	372,670	1,276	373,946

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent based on an energy equivalent basis. Of the Total Proved Natural Gas reserves estimated by Murphy above, 4,410 Mboe are attributed to fuel gas reserves in the Kaybob Duvernay and the Greater Tupper Montney Project combined.

Reserves Audit Opinion

McDaniel has used all data, assumptions, procedures and methods that it considers necessary to prepare this report.

In our opinion, the information relating to estimated proved reserves of bitumen and synthetic crude oil contained in this opinion has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30 and 932-235-50-31 of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, and 1202(a) (1), (2), (3), (4), (5), (8) of Regulation S-K of the Securities and Exchange Commission.

We have examined the assumptions, data, methods procedures and proved reserves estimates prepared by Murphy. In our opinion, the proved reserves for the reviewed properties as estimated by Murphy are, in aggregate on the basis of equivalent barrels, reasonable because when compared to our estimates, or if we were to perform our own detailed estimates, reflect a difference of not more than plus or minus 10 percent.

The analyses of these properties, as reported herein, was conducted within the context of an audit of a distinct group of properties in aggregate as part of the total corporate level reserves. Extraction and use of these analyses outside of this context may not be appropriate without supplementary due diligence.

McDaniel is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. McDaniel does not have any financial interest, including stock ownership, in Murphy. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Murphy.

Mr. Michael Verney, P.Eng., Executive Vice President has been with the firm since 2007 and has over 18 years of experience in the evaluation of oil and gas properties. As a senior engineer of McDaniel, Mr. Verney managed the preparation of the evaluation of the Murphy Oil Corporation's properties. Mr. Verney is a registered professional with the Association of Professional Engineers and Geoscientist of Alberta (APEGA).

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Murphy. It is not to be reproduced, distributed, or made available, in whole or in part to any person, company, or organization other than Murphy without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any of the estimates provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided was found to be erroneous.

If there are any questions, please contact Michael Verney directly at (403) 218-1377.

Sincerely,
McDANIEL & ASSOCIATES CONSULTANTS LTD.
APEGA PERMIT NUMBER: P3145

Michael Verney

Michael Verney, P.Eng.
Executive Vice President
January 19, 2026

MV:jep
[25-0165]

PERMIT TO PRACTICE
MCDANIEL & ASSOCIATES CONSULTANTS LTD.
RM SIGNATURE: Michael Verney
RM APEGA ID #: 90680
DATE: January 19, 2026
PERMIT NUMBER: P003145
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

CERTIFICATE OF QUALIFICATION

I, Michael Verney, Petroleum Engineer of 2000, 525 – 8th Avenue SW, Calgary, Alberta, Canada hereby certify:

1. That I am an Executive Vice President of McDaniel & Associates Consultants Ltd., APEGA Permit Number P3145, which Company did prepare, at the request of Murphy Oil Corporation, the audit letter entitled "Murphy Oil Corporation, Evaluation of the Canadian Oil and Gas Properties, As of December 31, 2025", dated January 19, 2026, and that I was involved in the preparation of this report. I am also registered as a Responsible Member as outlined by APEGA for McDaniel & Associates Consultant Ltd. APEGA Permit Number 3145.

2. That I attended the Queen's University in the years 2002 to 2006 and that I graduated with a Bachelor of Science degree in Engineering and a Bachelor of Arts degree in Economics, that I am a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Alberta and that I have in excess of 15 years of experience in oil and gas reservoir studies and evaluations.

3. That I have no direct or indirect interest in the properties or securities of Murphy Oil Corporation, nor do I expect to receive any direct or indirect interest in the properties or securities of Murphy Oil Corporation, or any affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

APEGA ID 90680
Calgary, Alberta
Dated: January 19, 2026

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 4, 2026

Mr. Jeffrey Wilson
Murphy Exploration & Production Company 9805 Katy Freeway, Suite G-200

Houston, Texas 77024 Dear Mr. Wilson:

In accordance with your request, we have audited the estimates prepared by Murphy Exploration & Production Company (Murphy E&P), as of December 31, 2025, of the proved reserves to the Murphy E&P interest in certain oil and gas properties located in federal waters in the Gulf of America. The scope of our work did not include auditing the future net revenue associated with these reserves. It is our understanding that Murphy E&P is a wholly owned subsidiary of Murphy Oil Corporation (Murphy Oil) and that the proved reserves estimates shown herein constitute approximately 6 percent of all proved reserves owned by Murphy Oil. Economic analysis was performed by Murphy E&P only to confirm economic producibility and determine economic limits for the properties. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, and economic producibility, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for Murphy Oil's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth Murphy E&P's estimates of the net reserves, as of December 31, 2025, for the audited properties:

	Net Reserves			
Category	Oil (MBBL)	NGL (MBBL)	Gas [(1)] (MMCF)	Oil Equivalent (MBOE)
Proved Developed	22,806	2,786	35,495	31,508
Proved Undeveloped	6,811	1,065	9,142	9,400
Total Proved	29,617	3,851	44,637	40,908

(1) Gas reserves are inclusive of fuel gas volumes expected to be consumed in field operations; fuel gas volumes are approximately 1 percent of the total proved reserves.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Oil equivalent volumes are expressed in thousands of barrels of oil equivalent (MBOE), determined using the ratio of 6 MCF of gas to 1 barrel of oil.

When compared on a field-by-field basis, some of the estimates of Murphy E&P are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of Murphy E&P's reserves are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by Murphy E&P in preparing the December 31, 2025, estimates of reserves, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by Murphy E&P.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves included herein have not been adjusted for risk. Murphy E&P's estimates do not include probable or possible reserves that may exist for these properties.

Oil, NGL, and gas prices were used only to confirm economic producibility and determine economic limits for the properties. Prices used by Murphy E&P are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2025. For oil and NGL volumes, the average NYMEX West Texas Intermediate spot price of $65.34 per barrel is adjusted by field for quality and market differentials. For gas volumes, the average Henry Hub spot price of $3.387 per MMBTU is adjusted by field for energy content and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $66.05 per barrel of oil, $15.81 per barrel of NGL, and $3.300 per MCF of gas (including fuel gas); the average adjusted gas price excluding fuel gas is $3.475 per MCF of gas.

Costs were used only to confirm economic producibility and determine economic limits for the properties. Operating costs used by Murphy E&P are based on historical operating expense records. These costs include the overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of Murphy E&P are included to the extent that they are covered under joint operating agreements for the operated properties. Capital costs used by Murphy E&P are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for facilities, a new well completion, workovers, new development wells, and production equipment. Abandonment costs used are Murphy E&P's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Operating, capital, and abandonment costs are not escalated for inflation.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of Murphy E&P and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Murphy E&P, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts used to confirm economic producibility and determine economic limits for the properties. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by Murphy E&P with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of Murphy E&P's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by Murphy E&P and Murphy Oil, are on file in our office. The technical persons primarily responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ John R. Cliver
John R. Cliver, P.E. 107216
Senior Vice President

Date Signed: February 4, 2026

By: /s/ Zachary R. Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: February 4, 2026

JRC:CDT

Exhibit 99.5

Murphy Oil Corporation

Proved Reserves Audit

Effective December 31, 2025
Project Number 25020
SEC Reseves Definitions

Hibernia and Terra Nova Assets, Canada

GLJ Ltd
1920, 401 - 9 Avenue SW
Calgary Alberta T2P 3C5

PROVED RESERVES AUDIT - SEC RESERVES DEFINITIONS

January 27, 2026

Project 25020

Jeffrey Wilson
General Manager, Corporate Reserves
Murphy Oil Corporation
9805 Katy Freeway Suite G-200
Houston, Texas, USA 77024

Dear Sir:

Re: Proved Reserves Audit – SEC Reserves Definitions
Hibernia and Terra Nova Assets, Canada
Effective December 31, 2025

At the request of Murphy Oil Corporation (the "Company"), GLJ Ltd. (GLJ) has conducted a reserves audit of the proved reserves estimates of the Hibernia and Terra Nova oil properties, owned by the Company and located offshore in Newfoundland, Canada. The effective date of the proved reserves is December 31, 2025 and the reserves audit was completed on January 21, 2026. The Company has represented that these properties account for 3 percent on a net oil equivalent barrel basis of the Company's net total proved reserves as of the effective date.

The estimates audited by GLJ were prepared by the Company in accordance with the reserves definitions of Regulation S-X Rule 4-10(a) of the U.S. Securities and Exchange Commission (SEC). GLJ's third party reserves audit was prepared for public disclosure by the Company in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

According to the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards) published by the Society of Petroleum Engineers (2019), "An audit is an examination of Reserves information that is conducted for the purpose of expressing an opinion as to whether such Reserves information, in the aggregate, is reasonable and has been estimated by qualified individuals and presented in conformity with generally accepted petroleum engineering and evaluation principles and in compliance with the relevant Reserves definitions".

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

The Company provided a table with their reserves estimates by field and all pertinent well and reservoir data such as geological maps, well logs, production and injection history, drill stem tests, workovers, pressure surveys, production tests, fluid analysis, and planned development activities. The proved reserves prepared by the Company for the properties that GLJ reviewed were estimated based on volumetric calculations, decline analysis, material balance methods or by any combination of the aforementioned methods depending on the available data.

The economic parameters such as operating costs, capital costs, process losses, abandonment cost and product pricing provided by the Company were reviewed, verified and accepted by GLJ. Prices, operating and capital costs, including maintenance capital, were provided by the Company.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the effective date estimated reserves.

GLJ has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report. For significant properties with performance-based assignments, GLJ reviewed the volumetric recovery to address the reasonableness of the assignment and development activity considered by the Company. In fields with significant performance and pressure data, the Company maps and geological models were accepted, but in cases where volumetric analysis formed the primary basis for the Company's reserves estimate, GLJ audited Company maps in more detail, including a review of associated geophysical interpretations.

Estimates of reserves and projections of production were generally prepared using well information and production data available to approximately July 31, 2025.

Based on our review, including the data, technical processes and interpretations presented by the Company, it is our opinion that the overall procedures and methodologies utilized by the Company in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations, and that the overall proved reserves for the reviewed properties as estimated by the Company are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent set forth in the SPE auditing standards. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

It is trusted that this audit meets your current requirements. Should you have any questions regarding this analysis, please contact the undersigned.

Yours truly,

GLJ LTD.

Patrick A. Olenick, P. Eng.
Senior Vice President

PAO/ljn
Attachments

INDEPENDENT PETROLEUM CONSULTANTS' CONSENT

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada has prepared Audit of **Murphy Oil Corporation** (the "Company") Canadian oil and gas properties and hereby gives consent to the use of its name and to the said estimates.

In the course of the audit, the Company provided GLJ Ltd. personnel with basic information which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans.

According to the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards) published by the Society of Petroleum Engineers (2019), "An audit is an examination of Reserves information that is conducted for the purpose of expressing an opinion as to whether such Reserves information, in the aggregate, is reasonable and has been estimated by qualified individuals and presented in conformity with generally accepted petroleum engineering and evaluation principles and in compliance with the relevant Reserves definitions".

Based on our review, including the data, technical processes and interpretations presented by the Company, it is our opinion that the overall procedures and methodologies utilized by the Company in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations, and that the overall proved reserves for the reviewed properties as estimated by the Company are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent set forth in the SPE auditing standards.

PERMIT TO PRACTICE
GLJ LTD.

RM Signature:

RM APEGA ID#: 73297

Date: January 27, 2026

PERMIT NUMBER: P 2066
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

Sarah C. Taylor, P.Geo.
Manager
January 27, 2026
ID#73044

Patrick A. Olenick, P.Eng.
Senior Vice President
January 27, 2026
ID#67686

GLJ LTD.
Corporate Seal

INTRODUCTION

GLJ Ltd. (GLJ) was commissioned by Murphy Oil Corporation (the "Company"), to prepare a reserves audit of the Company's proved (1P) reserves and net oil and gas reserves in the Hibernia and Terra Nova assets, located offshore in Newfoundland, Canada. The effective date of the reserves estimates is December 31, 2025 and the reserves audit was completed on January 21, 2026.

The estimates audited by GLJ were prepared by the Company based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission contained in the Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009, in the Federal Register (SEC regulations). GLJ's third party reserves audit was prepared for public disclosure by the Company in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

According to the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards) published by the Society of Petroleum Engineers (2019), "A Reserves audit is the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of Reserves and/or Reserves information prepared by others and the rendering of an opinion about the appropriateness of the methodologies used, the adequacy and quality of the data relied upon, the depth and thoroughness of the Reserves estimation process, the categorization of Reserves appropriate to the relevant definitions used, and the reasonableness of the estimated Reserves quantities and/or the Reserves information." (section 2.2 (g)). Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Estimates of reserves and projections of production were generally prepared using well information and production data available to approximately July 31, 2025.

Based on our review, including the data, technical processes and interpretations presented by the Company, it is our opinion that the overall procedures and methodologies utilized by the Company in preparing their estimates of the proved reserves as of December 31, 2025 comply with the current SEC regulations, and that the overall proved reserves for the reviewed properties as estimated by the Company are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent set forth in the SPE auditing standards.

For the reserves and income projections, the Company stated they used unweighted arithmetic average prices in effect at the first day of the month during the 12-month period prior to December 31, 2025 (the effective date), unless prices were defined by contractual arrangements, as required by the SEC regulations. Reserves were estimated by the Company to the economic limit of production. The following table sets forth the total proved net after royalty reserves under constant prices and costs as estimated by the Company attributable to the properties that GLJ reviewed:

NET 1P RESERVES ESTIMATED BY MURPHY OIL CORPORATION

Attributable to Certain Properties - Hibernia and Terra Nova
As of December 31, 2025

Category	Oil [1] (Mbbl)	Fuel Gas [2] (Mmcf)	(Mboe)
Proved Developed	14,751	8,604	16,185
Proved Undeveloped	4,577	-	4,577
Total Proved	**19,328**	**8,604**	**20,762**

Notes:
(1) Oil is produced oil and liquids separated from gas in the field
(2) Gas volumes consumed in operations and utilized for operation of equipment of the offshore platforms
(7) Barrels of oil equivalent were estimated assuming equivalency factors of 6 Mcf/boe for gas and 1 bbl/boe for all liquids

Liquid hydrocarbons are expressed in thousands of barrels (Mbbl) and gas volumes are expressed in millions of cubic feet (Mmcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net remaining reserves are also shown herein on an equivalent unit (boe) basis wherein natural gas is converted to oil equivalent barrels using equivalency factors of 6 Mcf/boe for gas and 1 bbl/boe for all liquids. Mboe represents thousand barrels of oil equivalent.

The Audit Procedure section outlines general procedures used in preparing this audit.

SEC RESERVES DEFINITIONS

The following definitions are excerpts from Regulation S-X 210.4-10. Portions of these definitions within square parentheses, [ ], have been transposed from other sections of Regulation S-X 210.4-10 to improve readability.

Resources

Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Reserves

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

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

Proved Oil and Gas Reserves

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

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

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

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

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

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

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

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

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

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

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

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

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

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

OTHER PERTINENT DEFINITIONS

Analogous Reservoir

Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Reasonable Certainty

If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable Technology

Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reservoir

A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

AUDIT PROCEDURE

The following outlines the methodology employed by GLJ Ltd. (GLJ) in conducting the evaluation of the Company's oil and gas properties. GLJ evaluation procedures are in compliance with standards and guidelines contained with the Society of Petroleum Engineers (SPE) Petroleum Resources Management System (PRMS)

INTEREST DESCRIPTIONS

The Company provided GLJ with current land interest information. The Company provided a representation letter confirming accuracy of land information. Certain cross-checks of land and accounting information were undertaken by GLJ in the audit of the assets. In this process, nothing came to GLJ's attention that indicated that information provided by the Company was incomplete or unreliable.

DATA PROVIDED

The Company provided a table with their reserves estimates by field. Additionally, all pertinent well, reservoir and economic data such as geological maps, well logs, production and injection history, drill stem tests, workovers, pressure surveys, production tests, fluid analysis, planned development activities, operating expenses, capital costs, abandonment cost, process losses, liquid yields, etc., were provided by the Company.

TECHNICAL REVIEW

GLJ performs a bottoms-up analysis where individual properties are audited. Auditors review historical production, well activity, mapping, pressure data and development plans as well as the evaluation approach used by the Company. Meetings with the Company were held to determine the Company's view of the reservoirs and technical justification for future development.

The reserves estimates prepared by the Company for the properties that GLJ reviewed were estimated based on volumetric calculations, decline analysis or material balance methods or by any combination of the aforementioned methods depending on the available data and the significance of the property within the overall corporate portfolio. Where possible, performance-based reserve assignments were made by the Company. For significant properties with performance-based assignments, GLJ reviewed the volumetric recovery to address the reasonableness of the assignment and development activity considered by the Company. In fields with significant performance and pressure data, the Company maps and geological models were accepted, but in cases where volumetric analysis formed the primary basis for the Company's reserves estimate, GLJ audited Company maps in more detail, including a review of associated geophysical interpretations.

Data used in the audit were obtained from Company personnel and Company files. In the preparation of our report GLJ accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, production, product transportation and marketing and sales agreements, capital costs, operating expense data, and capital cost estimates. If, in the course of the audit, the validity or sufficiency of any material information was brought into question, GLJ did not rely on such information until such concerns were satisfactorily resolved.

The economic parameters such as operating costs, capital costs, process losses, abandonment cost and product pricing provided by the Company were reviewed, verified and accepted by GLJ. Prices, operating and capital costs, including maintenance capital, were provided by the Company.

Reserves were estimated by the Company to the economic limit of production.

MARKETABLE PRODUCTS

Recoverable reserves were estimated by the Company to the following products:

Oil	Produced oil and liquids separated from gas in the field
Fuel Gas	Gas volumes consumed in operations and utilized for operation of equipment on the offshore platforms.

In this report, quantities of hydrocarbons have been converted to barrels of oil equivalent (boe); or to sales gas equivalent (sge) using factors of 6 Mcf/boe for gas, 1 bbl/boe for all liquids, and 0 boe for sulphur. Users of oil equivalent values are cautioned that while boe based metrics are useful for comparative purposes, they may be misleading when used in isolation.

LIST OF ABBREVIATIONS

AOF	absolute open flow
bbl	barrels
Bcf	billion cubic feet of gas at standard conditions
BIIP	bitumen initially-in-place
boe	barrel of oil equivalent, in this evaluation determined using 5.2 Mcf/boe for gas, 1 bbl/boe for all liquids, and 0 boe for sulphur
bopd	barrels of oil per day
Btu	British thermal units
bwpd	barrels of water per day
DSU	drilling spacing unit
GCA	gas cost allowance
GIIP	gas initially-in-place
GOC	gas-oil contact
GOR	gas-oil ratio
GORR	gross overriding royalty
GWC	gas-water contact
Mbbl	thousand barrels
Mboe	thousand boe
Mcf	thousand cubic feet of gas at standard conditions
Mcfe	thousand cubic feet of gas equivalent
Mlt	thousand long tons
M$	thousand dollars

MM$	million dollars
MMbbl	million barrels
MMboe	million boe
MMBtu	million British thermal units
MMcf	million cubic feet of gas at standard conditions
MRL	maximum rate limitation
Mstb	thousand stock tank barrels
MMstb	million stock tank barrels
NGL	natural gas liquids (ethane, propane, butane and condensate)
NPI	net profits interest
OIIP	oil initially-in-place
ORRI	overriding royalty interest
OWC	oil-water contact
P&NG	petroleum and natural gas
PIIP	petroleum initially-in-place
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	pressure-volume-temperature
RLI	reserves life index, calculated by dividing reserves by the forecast of first year production
scf	standard cubic feet
sge	sales gas equivalent – if presented in this evaluation, determined using 1 barrel of oil or natural gas liquid = 5.2 Mcfe; 0 for sulphur
stb	stock tank barrel
WI	working interest
WTI	West Texas Intermediate

PRODUCT PRICE AND MARKET FORECASTS

December 31, 2025

The Company provided its SEC constant pricing for the West Texas Intermediate oil (WTI), Brent oil and Henry Hub natural gas benchmarks, which are calculated as the unweighted arithmetic average of the first day-of-the-month price for each month within the period prior to the effective date of the report. The table presented below summarizes the benchmark pricing provided by the Company and utilized in the reserves audit.

The Company realizes an average received oil price of $68.21 USD/bbl after adjustments for oil quality and transportation. There are no gas sales within the Company's assets, all gas production is either re-injected or consumed in operation as fuel gas.

			WTI Crude Oil (39.6 API, 0.24%S) Cushing, OK		Brent Crude Oil (38.3 API, 0.37%S) UK
Year	Inflation %	CADUSD Exchange Rate USD/CAD	Constant 2026 $ USD/bbl	Then Current USD/bbl	Then Current USD/bbl
2026	0.0	0.7142	65.34	65.34	69.42
2027	0.0	0.7142	65.34	+0%/yr	+0%/yr

CERTIFICATES OF QUALIFICATION

Patrick A. Olenick
Ryan Campbell
Jordan J.K. Hughes
Julisa Rocabado

CERTIFICATION OF QUALIFICATION

CERTIFICATION OF QUALIFICATION

I, Patrick A. Olenick, Professional Engineer, 1920, 401 – 9th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Ltd., which company did prepare a detailed audit of certain oil and gas properties of Murphy Oil Corporation (the "Company"). The effective date of this audit is December 31, 2025.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary where I graduated with a Bachelor of Science Degree in Mechanical Engineering in 2003; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-four years' experience in engineering studies relating to oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.

PROFESSIONAL ENGINEER ALBERTA
PATRICK A. OLENICK

January 27, 2026
ID# 67686

CERTIFICATION OF QUALIFICATION

I, Ryan Campbell, Professional Engineer, 1920, 401 – 9th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Ltd., which company did prepare a detailed audit of certain oil and gas properties of Murphy Oil Corporation (the "Company"). The effective date of this audit is December 31, 2025.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary and that I graduated with a Chemical Engineering Degree and Minor in Petroleum Engineering in 2008; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of eighteen years experience in engineering studies relating to oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.

PROFESSIONAL ENGINEER ALBERTA
RYAN CAMPBELL
ID 82079

Ryan Campbell

January 27, 2026

CERTIFICATION OF QUALIFICATION

I, Jordan James Keith Hughes, Professional Geoscientist, 1920, 401 – 9th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Ltd., which company did prepare a detailed audit of certain oil and gas properties of Murphy Oil Corporation (the "Company"). The effective date of this audit is December 31, 2025.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary where I graduated with a Bachelor of Science Degree in Geophysics, 2013; that I am a Registered Professional Geoscientist in the Province of Alberta; and, that I have in excess of twelve years experience in geoscience studies relating to oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.

PROFESSIONAL GEOSCIENTIST ALBERTA
JORDAN JAMES KEITH HUGHES

January 27, 2026
ID# 164074

CERTIFICATION OF QUALIFICATION

I, Julisa Rocabado, Professional Engineer, 1920, 401 – 9th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Ltd., which company did prepare a detailed audit of certain oil and gas properties of Murphy Oil Corporation (the "Company"). The effective date of this audit is December 31, 2025.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the Universidad Autonoma Gabriel Rene Moreno where I graduated with a Bachelor Degree in Petroleum Engineering in 2012; and that I have in excess of eleven years experience in engineering studies relating to oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.

PROFESSIONAL ENGINEER ALBERTA
JULISA
ROCABADO
JUSTINIANO
ID 294733
LICENSED TO PRACTICE

January 27, 2026