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, 2023

OR

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

Commission file number 1-8590

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, 2023) – $4,406,165,207.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2024 was 152,755,027.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 08, 2024 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

2023 FORM 10-K

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a global oil and gas exploration and production 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 U.S. downstream business was separated from Murphy Oil Corporation's oil and gas exploration and production business. For reporting purposes, Murphy's exploration and production activities are subdivided into three geographic segments, including the United States, 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 exploration and production segments. The Company's corporate headquarters are located in Houston, Texas.

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 10.

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 45, 74 through 76, 77 through 78, 98 through 100, and 103 through 118 of this Form 10-K report.

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, natural gas and natural gas liquids primarily in the U.S. and Canada and explores for crude oil, natural gas and natural gas liquids in targeted areas worldwide.

During 2023, Murphy's principal exploration and production activities were conducted in the United States by wholly-owned Murphy Exploration & Production Company – USA (Murphy Expro USA) and its subsidiaries, in Canada by wholly-owned Murphy Oil Company Ltd. and its subsidiaries and in Australia, Brazil, Brunei, Côte d'Ivoire, Mexico and Vietnam by wholly-owned Murphy Exploration & Production Company – International (Murphy Expro International) and its subsidiaries. Murphy's operations and production in 2023 were in the United States, Canada and Brunei.

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

Murphy's worldwide 2023 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 192,640 barrels of oil equivalent per day, an increase of 10.0% compared to 2022.

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 2023 production and sales volume see pages 35 to 36.

United States

In the United States, Murphy produces crude oil, natural gas liquids and natural gas primarily from fields in the Gulf of Mexico and in the Eagle Ford Shale area of South Texas. The Company produced 108,084 barrels of crude oil and natural gas liquids per day and approximately 96 MMCF of natural gas per day in the U.S. in 2023. These amounts represented 94.0% of the Company's total worldwide oil and natural gas liquids and 20.6% of worldwide natural gas production volumes.

Offshore

The Company holds rights to approximately 600 thousand gross acres in the Gulf of Mexico. During 2023, approximately 73% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico, of which approximately 90% was derived from ten fields, including St. Malo, Samurai, Khaleesi, Mormont, Cascade and Chinook, Kodiak, Lucius, Neidermeyer, Marmalard and Front Runner. Total average daily production in the Gulf of Mexico in 2023 was 79,397 barrels of crude oil and natural gas liquids and 70 MMCF of natural gas. At December 31, 2023, Murphy had total proved reserves for Gulf of Mexico fields of 132.3 million barrels of oil and natural gas liquids and 100.7 billion cubic feet of natural gas.

Onshore

The Company holds rights to approximately 133 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and natural gas play. During 2023, approximately 27% of total U.S. hydrocarbon production was produced in the Eagle Ford Shale. Total 2023 production in the Eagle Ford Shale area was 28,641 barrels of oil and liquids per day and 25.7 MMCF per day of natural gas. At December 31, 2023, the Company's proved reserves for the U.S. Onshore business totaled 130 million barrels of liquids and 192.4 billion cubic feet of natural gas.

Canada

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

Onshore

Murphy has approximately 139 thousand gross acres of Tupper Montney mineral rights located in northeast British Columbia. In addition, the Company holds a 70% operated working interest in Kaybob Duvernay lands in Alberta. The Company has approximately 165 thousand gross acres of Kaybob Duvernay mineral rights. Daily production in 2023 in Onshore Canada averaged 3,618 barrels of liquids and 370 MMCF of natural gas, which included production from our divested Placid Montney of 274 barrels of liquids and 3 MMCF of natural gas. Total Onshore Canada proved liquids and natural gas reserves at December 31, 2023, were approximately 16.4 million barrels and 2.2 trillion cubic feet, respectively.

Offshore

The Company holds a non-operated interest in approximately 133 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% working interest in Terra Nova.

Oil production in 2023 was 2,780 barrels of oil per day for Hibernia.

In 2023, the Terra Nova asset life extension project was completed and production restarted at the end of November. Production is expected to ramp up over the coming months. Total oil production in 2023 was 240 barrels of oil per day for Terra Nova.

Total proved reserves for offshore Canada at December 31, 2023 were approximately 22.3 million barrels of liquids and 14.8 billion cubic feet of natural gas.

Brazil

The Company holds a 20% non-operated working interest in nine blocks in the offshore regions of the Sergipe-Alagoas Basin (SEAL) in Brazil (SEAL-M-351, SEAL-M-428, SEAL-M-430, SEAL-M-501, SEAL-M-503, SEAM-M-505, SEAL-M-573, SEAL-M-575 and SEAL-M-637).

Murphy has 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, 2023 is approximately 2.5 million 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, 2023.

Oil production in 2023 was 250 barrels of oil per day for Brunei.

Total proved reserves for our Jagus East discovery in Block CA-1 at December 31, 2023 were approximately 0.3 million barrels of liquids and 188 million cubic feet of natural gas. Block CA-1 covers 2 thousand gross acres.

Mexico

Murphy holds a 40% working interest and is the operator of Block 5 in the deepwater Salina Basin. The block covers approximately 623 thousand gross acres, with water depths ranging from 2,300 to 3,500 feet (700 to 1,100 meters). The license contract is currently in the first additional exploration period, which expires in May 2025 and has no outstanding commitments. In 2022, an exploration well was drilled and did not find commercial hydrocarbons.

Vietnam

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

Block 15-1/05 contains the Lac Da Vang (LDV) discovered field in the Cuu Long Basin where the Declaration of Commerciality was made in January 2019, and the field Outline Development Plan was approved by Petrovietnam in August 2019. The Lac Da Trang (LDT) 1X exploration well, the last remaining commitment of the PSC, was completed in April 2019. 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. The Company anticipates drilling an exploration well in 2024.

In Block 15-2/17, the Company completed its seismic study program, which included 3D seismic reprocessing. In 2024 the Company anticipates drilling an exploration commitment well.

In blocks 144 and 145, the Company acquired 2D seismic in 2013 and undertook seabed surveys in 2015 and 2016. The Company will be seeking an extension to complete the remaining seismic commitment.

Total proved reserves for Vietnam at December 31, 2023 were approximately 12.1 million barrels of liquids and 2.8 billion cubic feet of natural gas.

Côte d’Ivoire

During the second quarter of 2023, Murphy signed PSCs as operator in five deepwater blocks in the Tano Basin offshore Côte d’Ivoire in Africa. The five blocks have a total area of 1.5 million gross acres, with Murphy initially holding a 90% working interest in four blocks and 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.

Commitments for the initial exploration periods across the five blocks consist of seismic reprocessing. Block CI-103 includes the Paon discovery, appraised with multiple wells by a previous operator. The PSC for this block also includes a commitment to submit a field development plan for this discovery by the end of 2025.

Proved Reserves

Total proved reserves for crude oil, natural gas liquids and natural gas as of December 31, 2023 are presented in the following table.

	Proved Reserves			
	All Products	Crude Oil	Natural Gas Liquids	Natural Gas [4]
Proved Developed Reserves:	(MMBOE)	(MMBBL)		(BCF)
United States	**223.2**	**163.7**	**24.1**	**212.4**
Onshore	109.4	70.3	16.3	136.7
Offshore [1]	113.8	93.4	7.8	75.7
Canada	**202.0**	**22.3**	**1.8**	**1,066.7**
Onshore	183.4	6.0	1.8	1,053.0
Offshore	18.6	16.3	—	13.7
Other	**0.3**	**0.3**	**—**	**0.2**
Total proved developed reserves	**425.5**	**186.3**	**25.9**	**1,279.3**
Proved Undeveloped Reserves:				
United States	**87.9**	**64.3**	**10.2**	**80.7**
Onshore	52.7	35.8	7.6	55.7
Offshore [2]	35.2	28.5	2.6	25.0
Canada	**213.5**	**13.1**	**1.5**	**1,193.4**
Onshore	207.3	7.1	1.5	1,192.3
Offshore	6.2	6.0	—	1.1
Other	**12.6**	**12.1**	**—**	**2.8**
Total proved undeveloped reserves	**314.0**	**89.5**	**11.7**	**1,276.9**
Total proved reserves [3]	**739.5**	**275.8**	**37.6**	**2,556.2**

[1] Includes proved developed reserves of 12.8 MMBOE, consisting of 11.7 million barrels of oil (MMBBL) oil, 0.5 MMBBL NGLs and 3.8 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[2] Includes proved undeveloped reserves of 2.7 MMBOE, consisting of 2.3 MMBBL oil, 0.1 MMBBL NGLs and 1.5 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[3] Includes proved reserves of 15.5 MMBOE, consisting of 14.0 MMBBL oil, 0.6 MMBBL NGLs and 5.3 BCF natural gas, attributable to the noncontrolling interest in MP GOM.

[4] Includes proved natural gas reserves to be consumed in operations as fuel of 71.3 BCF, 41.9 BCF and 2.8 BCF for the U.S. Canada and Other, respectively, with 1.2 BCF attributable to the noncontrolling interest in MP GOM.

Murphy Oil's 2023 total proved reserves and proved undeveloped reserves are reconciled from 2022 as presented in the table below:

(Millions of oil equivalent barrels) [1]	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	715.4	279.4
Revisions of previous estimates	(13.3)	(3.7)
Extensions and discoveries	112.6	111.2
Improved recovery	0.4	0.4
Conversions to proved developed reserves	–	(73.3)
Sale of properties	(5.2)	–
Production	(70.4)	–
End of year [2]	**739.5**	**314.0**

[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 (MCF) of natural gas to one barrel of oil.

[2] Includes 15.5 MMBOE and 2.7 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.

During 2023, Murphy's total proved reserves increased by 24.1 million barrels of oil equivalent (MMBOE). The increase in reserves principally relates to extensions of 86.4 MMBOE in Onshore Canada, 11.7 MMBOE in the Eagle Ford Shale, 12.6 MMBOE in Vietnam, 1.1 MMBOE in the Gulf of Mexico, and 0.9 MMBOE in Offshore Canada. These revisions were offset by production of 70.4 MMBOE in 2023, performance and price related reductions of 11.4 MMBOE in the Eagle Ford Shale and 1.9 MMBOE in the Gulf of Mexico, and disposition of 5.2 MMBOE in Onshore Canada.

Murphy's total proved undeveloped reserves at December 31, 2023 increased 34.6 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2023 were predominantly attributable to four areas: the U.S. Gulf of Mexico, the Eagle Ford Shale in South Texas, Tupper Montney in Onshore Canada and Offshore Vietnam. The U.S. and Canadian assets had active development work ongoing during the year, while the Tupper Montney had increased capital allocations and the Lac Da Vang development project in Vietnam was sanctioned. The majority of proved undeveloped reserves associated with revisions of previous estimates was the result of performance adjustments in Tupper Montney and the Eagle Ford Shale and negative price revisions in the U.S. Onshore and U.S. Offshore fields, and were substantially offset by positive price revisions in Tupper Montney from decreased royalty rates and decelerated royalty incentive payouts arising from lower commodity prices. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in Tupper Montney, the Gulf of Mexico, and the Eagle Ford Shale and the completion of the Terra Nova field life extension project in Offshore Canada. Other proved undeveloped increases resulted from sanctioned development plans for the Longclaw field in the Gulf of Mexico and Lac Da Vang field in Vietnam.

The Company spent approximately $704 million in 2023 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 $700 million per year to move current undeveloped proved reserves to the developed category. The anticipated level of spending in 2024 primarily includes drilling and development in the Gulf of Mexico, Eagle Ford Shale, Tupper Montney and Vietnam areas.

At December 31, 2023, proved reserves are included for several development projects, including oil developments in the Eagle Ford Shale in South Texas, deepwater Gulf of Mexico, Kaybob Duvernay in Onshore Canada and Lac Da Vang in Vietnam; as well as natural gas developments in Tupper Montney in Onshore Canada. Total proved undeveloped reserves associated with various development projects at December 31, 2023 were approximately 314.0 MMBOE, which represents 42% 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. The Company currently operates deepwater fields in the Gulf of Mexico that have two undeveloped locations that exceed this five-year window. Total reserves associated with the two locations amount to less than 1% of the Company's total proved reserves at year-end 2023. 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 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." 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 and condensate, natural gas liquids (NGL) and natural gas 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 gas operational management and technical personnel. The Reserves General Manager joined Murphy in 2020 and has more than 32 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 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 ensure compliance with the rules and regulations of the SEC.

The Reserves General Manager coordinates and oversees the third-party audits which are performed annually. In 2023, third party audits were conducted for proved reserves covering 96.6% 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, 2023. The Ryder Scott summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for Ryder Scott has over 21 years of industry experience, joining Ryder Scott over 18 years ago. He is a registered Professional Engineer in the State of Texas.

McDaniel & Associates ("McDaniel") performed audits for certain reserve estimates of our Canadian fields as of December 31, 2023. The McDaniel summary report is filed as an exhibit to this Annual Report on Form 10-K. The two technical advisors for McDaniel both have over 17 years of experience in the estimation and evaluation of reserves with McDaniel. Both are registered Professional Engineers with the Association of Professional Engineers and Geoscientists of Alberta.

Gaffney, Cline & Associates Pte Ltd ("GaffneyCline") performed audits for certain reserve estimates of our Vietnam fields as of December 31, 2023. The GaffneyCline summary report is filed as an exhibit to this Annual Report on Form 10-K. The team lead for GaffneyCline has over 40 years of industry experience, joining GaffneyCline over 19 years ago.

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 liquids and natural gas for the last three years are presented by geographic area on pages 105 through 112 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 United States 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, condensate and natural gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2023 are shown on page 34 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 103 through 118 of this Form 10-K report.

Acreage and Well Count

At December 31, 2023, 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	111	97	22	22	133	119
	Gulf of Mexico	59	26	541	288	600	314
Total United States		170	123	563	310	733	433
Canada	Onshore	129	105	175	138	304	243
	Offshore	105	12	28	1	133	13
Total Canada		234	117	203	139	437	256
Mexico		–	–	623	249	623	249
Brazil		–	–	2,453	1,110	2,453	1,110
Brunei		2	–	–	–	2	–
Vietnam		–	–	7,324	4,571	7,324	4,571
Côte d'Ivoire		–	–	1,489	1,332	1,489	1,332
Totals		406	240	12,655	7,711	13,061	7,951

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

Scheduled expirations in 2024 include 4,521 thousand net acres in Vietnam, 52 thousand net acres in in the Gulf of Mexico and 6 thousand net acres in Onshore Canada. Murphy has applied for and anticipates receiving lease extensions in Vietnam.

Acreage currently scheduled to expire in 2025 include 249 thousand net acres in Mexico, 75 thousand net acres in Brazil, 6 thousand net acres in the Gulf of Mexico and 1 thousand net acres in Onshore Canada.

Scheduled expirations in 2026 include 27 thousand net acres in the Gulf of Mexico and 6 thousand net acres in Offshore Canada.

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 that is known to be productive.

The following table shows the number of oil and natural gas wells producing or capable of producing at December 31, 2023.

		Oil Wells		Natural Gas Wells	
		Gross	Net	Gross	Net
Country					
United States	Onshore	1,184	949	30	4
	Gulf of Mexico	80	36	14	6
Total United States		1,264	985	44	10
Canada	Onshore	20	14	342	326
	Offshore	48	5	—	—
Total Canada		68	19	342	326
Totals		1,332	1,004	386	336

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
2023								
Exploration	**–**	**1.3**	**–**	**–**	**–**	**–**	**–**	**1.3**
Development	**34.1**	**–**	**15.1**	**–**	**–**	**–**	**49.2**	**—**
2022								
Exploration	–	–	–	–	–	0.6	–	0.6
Development	29.1	–	22.1	–	–	–	51.2	–
2021								
Exploration	–	0.1	–	–	–	–	–	0.1
Development	27.9	–	14.6	–	–	–	42.5	–

Murphy’s drilling wells in progress at December 31, 2023 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
Country							
United States	Onshore	–	–	6.0	1.3	6.0	1.3
	Gulf of Mexico	1.0	0.1	3.0	0.8	4.0	0.9
Canada	Onshore	–	–	11.0	11.0	11.0	11.0
	Offshore	–	–	–	–	–	–
Totals		1.0	0.1	20.0	13.1	21.0	13.2

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, 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 gas will continue to play a vital role in the long-term energy mix.

We are committed to reducing our 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. The Company has established a 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 2023 Sustainability Report, located on the Company's website, for details.

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 liability, 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 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 Mexico 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 Mexico, 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 Mexico. 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 gas sector due to their association with climate change. In addition, international climate efforts, including the 2015 "Paris Agreement" and the recent Conferences of the Parties of the UN Framework Convention on Climate Change (COP26, COP27, and COP28, respectively), 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 Mexico and onshore in south Texas and in its Canadian onshore 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 GHG, 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.

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.

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

We publish an annual sustainability report according to 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 2023, we published our fifth annual sustainability report, located on the Company's website.

Human Capital Management

At Murphy, we believe in providing energy that empowers people, and that is what our 725 employees do every day. As of December 31, 2023, we had 438 office-based employees and 287 field employees, all of whom are guided by our mission, vision, values and behaviors. Together with the Executive Leadership Team, the Vice President, Human Resources and Administration, who reports directly to our 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
- Diversity, Equity and Inclusion
- Health and Welfare Benefits

The Board receives related updates from the Vice President, Human Resources and Administration on a regular basis including the review of compensation, benefits, succession and talent development, along with diversity, equity and inclusion.

Employee Compensation Programs

Our purpose, to empower 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. For further detail 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 8, 2024.

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 behavior to align with the Company's mission, vision, values and behaviors
- Develop employee capabilities through effective feedback and coaching
- Maintain a process that is consistent throughout the organization to measure employee performance that is tied to Company and stockholder 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 behaviors that support our mission, vision, values and contributions toward executing our Company's goals/business strategy.

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 now have access to LinkedIn Learning with more than 15,000 courses, Continuing Education Unit (CEU) credit and certification opportunities, and access to expert instructors. We also administer mandatory compliance training for our employees through My Murphy Learning with a 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 the Company's Scorecard and understanding of annual incentive plans, three training courses were introduced covering the following topics: (1) Free Cash Flow and return metrics; (2) Lease Operating Expenses (LOE) and General and Administrative; and (3) Total Recordable Incident Rate, Spill Rate and Emissions. These training opportunities, 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. Over eighty managers participated in leadership programs, from a top rated business school, addressing focus areas such as strategic agility, enterprise thinking, building high-performing teams and enhancing trust.

We encourage employee engagement and solicit feedback through internal surveys and our employee-led Ambassador program to gain insights 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 2023, our voluntary employee turnover rate was 6.0%.

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 in Murphy's achieving success. As such, we provide our employees and their families with a comprehensive set of subsidized benefits that are competitive and aligned to 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 either through the Company Matching Gift Program, "Impact – Murphy Makes a Difference" Program or on their own and receive 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.

Diversity, Equity and Inclusion

We are committed to fostering work environments that value diversity, equity and inclusion (DE&I). This commitment includes providing equal access to and participation in programs and services without regard to race, creed, religion, color, national origin, disability, sex (including pregnancy), sexual orientation, gender identity, veteran status, age or stereotypes or assumptions based thereon. We also support interest-based groups such as sports, hobbies and charity volunteering. We welcome our employees' differences, experiences and beliefs and we are investing in a more productive, engaged, diverse and inclusive workforce. The Board receives DE&I updates on demographic data, strategic partnerships, recruiting strategies and programs from the Vice President, Human Resources and Administration on a regular cadence.

We seek input and program recommendations from our DE&I Committee and through the sponsorship of our Vice President, Human Resources and Administration. Our DE&I Committee consists of diverse employees at various levels from across the organization that share a passion for DE&I. Our Board currently includes three directors who are women, with at least one woman on each committee. Our Nominating and Governance Committee is actively focused on DE&I issues as part of its overall mandate.

Female Representation (U.S. and International)	December 31, 2023
Executive and Senior Level Managers	21 %
First- and Mid-Level Managers	22 %
Professionals	33 %
Other (Administrative Support and Field)	7 %
Total	**22 %**

Minority [1] Representation (U.S.-Based Only)	December 31, 2023
Executive and Senior Level Managers	32 %
First- and Mid-Level Managers	28 %
Professionals	42 %
Other (Administrative Support and Field)	30 %
Total	**35 %**

[1] As defined by the U.S. Equal Employment Opportunity Commission.

We believe that it is important we attract employees with diverse backgrounds where we operate and are focusing on attracting and retaining women and minorities in our workforce ensuring a vibrant talent pipeline.

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 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 crude oil, natural gas liquids 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 crude oil and natural gas that it produces. Many of the factors influencing prices of crude oil and natural gas are beyond our control. These factors include:

- worldwide and domestic supplies of, and demand for, crude oil, natural gas liquids 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, amongst others, production levels in the shale plays in the United States;
- political instability or armed conflict in oil and gas producing regions, such as the Russia-Ukraine conflict and Israeli-Palestinian conflict;
- the level of drilling, completion and production activities by other exploration and production 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 affecting energy consumption and energy supply;
- increased activism against, or change in public sentiment for, oil and 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 and taxes, including 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 $77.62 per barrel in 2023, compared to $94.23 in 2022 and $67.91 in 2021. 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 (MEH), Heavy Louisiana Sweet (HLS) and Brent.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was $2.53 per million British Thermal Units (MMBTU) in 2023, compared to $6.38 in 2022 and $3.84 in 2021. The Company also has exposure to the Canadian benchmark natural gas price, Alberta Energy Company (AECO), which averaged C$2.64 per MCF in 2023, compared to C$5.31 in 2022 and C$3.63 in 2021. The Company has entered into certain forward fixed price contracts as detailed in the Outlook section beginning on page 51 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 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 will 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 gas industry and experiences competition from other oil and gas companies, which include major integrated oil companies, independent producers of oil and 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 subjects its exploration and production 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 2023, the Company participated in three exploration wells. The Longclaw #1 well (Green Canyon 433), located in the Gulf of Mexico, resulted in a commercial discovery while the Oso #1 (Atwater Valley 138) and Chinook #7 (Walker Ridge 425) wells, located in the Gulf of Mexico, failed to encounter commercial hydrocarbons. Additionally, the Company expensed previously suspended costs associated with the 2019 Cholula-1EXP well which was determined to be non-commercial. The Company has budgeted $120 million for its 2024 exploration program, which includes drilling two operated wells in Vietnam and two non-operated wells in the Gulf of Mexico.

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 exploration and production 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 liquids, and natural gas included in this report on pages 103 through 112 have been prepared according to the SEC guidelines by qualified company personnel or qualified independent engineers based on an unweighted average of crude oil, NGL 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 crude oil, NGL 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 2023, 96.6% 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, 2023, and including noncontrolling interests, approximately 32% of the Company’s crude oil and condensate proved reserves, 31% of natural gas liquids proved reserves and 50% 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 116 and 117 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 2023, approximately 18% of the Company’s total production was at fields operated by others, while at December 31, 2023, approximately 13% 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 exploration and production 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 U.S. Gulf of Mexico, 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, and 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. 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 December 2023, the U.S. EPA announced 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. 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 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 Kaybob Duvernay and 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 be increased. Once new laws and/or regulations have been enacted and adopted, the costs of compliance are appraised.

In addition, the U.S. Bureau of Ocean Energy Management (BOEM) and the U.S. Bureau of Safety and Environmental Enforcement (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 Mexico, 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 Mexico, 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 current presidential 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 gas leases on public lands and offshore waters, and the Secretary of Interior's related review of permitting and leasing practices, could adversely impact Murphy's operations. Despite the pauses on oil and gas leases in 2021, in August 2022, the Inflation Reduction Act 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 Mexico and Alaska within two years. These developments demonstrate the uncertainty regarding the current presidential administration's approach to oil and gas leasing and permitting. 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 gas exploration, development, and production activities and sustainability considerations, including climate change and the transition to a lower carbon economy.

Opposition toward oil and gas drilling, development, and production activity has been growing globally. Companies in the oil and 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.

Activism may continue to increase regardless of whether the current presidential administration in the U.S. is perceived to be following, or actually follows, through on the current president’s campaign commitments to promote decreased fossil fuel exploration and production in the U.S., including as a result of the administration’s environmental and climate change executive orders described earlier in this 10-K. Our need to incur costs associated with responding to these initiatives or complying with any resulting new legal or regulatory 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 gas industry could result in a reduction in the demand for our products or otherwise affect our results of operations or financial condition.

While the Company has been named a co-defendant with other oil and 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. In November 2022, the Company entered into an $800 million revolving credit facility (RCF). The RCF is a senior unsecured guaranteed facility and will expire in November 2027. As of December 31, 2023, the Company had no outstanding borrowings under the 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 exploration and production 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 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, 2023.

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. 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 Sheet.

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 exploration and production 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 gas industry. In addition, periods of inflationary pressure in the wider economy, as seen during 2022, can also lead to a similar increase in the cost of goods and services for the Company. Murphy has a dedicated procurement department 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 partly protected from the increasing 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 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. These joint venture partners may not be able to meet their financial obligation to pay for their share of capital and operating costs as they become due
- 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 COVID-19, or that of any other pandemic, 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 crude oil, natural gas liquids and natural gas can significantly affect the Company's operating results."

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 the COVID-19 or other pandemic, our operations will likely be impacted and decrease our ability to produce oil, natural gas liquids and natural gas. We may be unable to perform fully on our commitments and our costs may increase as a result of the COVID-19 or other outbreak. These cost increases may not be fully recoverable or adequately covered by insurance.

The COVID-19 or other pandemic 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 ongoing impact of the COVID-19 or other pandemic. The extent to which the COVID-19 or other health pandemics or epidemics 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 United States under federal, state and local jurisdictions and in the foreign jurisdictions in which we operate. Tax laws, regulations 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 or earnings in a given taxing jurisdiction or our ownership or capital structure. For example, on August 16, 2022, the United States enacted the Inflation Reduction Act of 2022, which is highly complex, subject to interpretation and contains significant changes to U.S. tax law, including, but not limited to, a 15% corporate book minimum tax for taxpayers with adjusted financial statement income exceeding an average of $1 billion over three years and a 1% excise tax on certain stock repurchases made after December 31, 2022. The U.S. Department of the Treasury and the IRS are expected to release further regulations and interpretive guidance implementing the legislation contained in the Inflation Reduction Act of 2022, but the details and timing of such regulations are subject to uncertainty at this time. The tax provisions of the Inflation Reduction Act of 2022 that may apply to us are generally effective in 2023 or later. We continue to analyze the potential impact of the Inflation Reduction Act of 2022 on our consolidated financial statements and to monitor guidance to be issued by the U.S. Department of the Treasury. However, 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 may not be able to hire or retain qualified personnel to support our operations.

The success of our operations is dependent upon our ability to hire and retain qualified and experienced personnel. Changes in public sentiment for oil and gas exploration, development, and production activities and considerations including climate change and the transition to a lower carbon economy may make it more difficult for us to attract such qualified personnel. Additionally, the cost to attract and retain qualified personnel has increased in recent years due to competition and may increase substantially in the future. If there is a decrease in the availability of qualified personnel, this may materially and adversely affect our results of operations, cash flows and financial condition.

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct exploration, development, and production activities. We are no exception to this trend. As a company, 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 preventing breaches is critical to our business operation. We rely on our information systems, and our cybersecurity training and policies, to protect and secure intellectual property, strategic plans, customer information, and personally identifiable information, such as employee information.

A cyber infrastructure failure or a successfully executed, undetected cyber attack could significantly disrupt business operations. It might lead to downtime, revenue loss, and increased costs for remediation. Additionally, the compromise, theft, or unauthorized release of critical data could damage our reputation, weaken our competitive edge, and negatively impact our financial stability. Due to the nature of cyber-attacks, breaches to our systems could go undetected for a prolonged period of time.

As the sophistication of cyber threats continues to evolve, we may be required to dedicate additional resources to continue to modify or enhance our security measures, or to investigate and remediate any vulnerabilities to cyber-attacks. 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 failure to comply with these laws and regulations could result in significant penalties and legal 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, following the election and inauguration of the current U.S. President in January 2021, the U.S. Secretary of the Interior issued Order No. 3395 on January 20, 2021. This order served to potentially impact the timing of issuance of oil and gas leases, lease amendments and extension, and drilling permits on federal lands and offshore waters. Following this notice, the Department of Interior has continued to approve permits, however, Murphy may experience delays in project approvals when the order is enforced. An extension or permanency of this regime could impact the options available to Murphy for future development, reserves available for production and hence future cash flows and profitability. The Company does not hold any onshore federal lands in the U.S.

In addition, the current presidential administration has pursued other initiatives related to environmental, health and safety standards applicable to the oil and gas industry. These include an executive order in January 2021 that directed the Secretary of the Interior to halt indefinitely new oil and gas leases on federal lands and offshore waters pending a since-completed review by the Secretary of the Interior of federal oil and 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 current presidential administration from implementing the pause in new federal oil and 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 Inflation Reduction Act 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 Mexico 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 gas lease sales in the Gulf of Mexico through 2029. These developments demonstrate the uncertainty regarding the current presidential administration's approach to oil and gas leasing and permitting.

In March 2022, the SEC proposed rules requiring disclosure of a 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, Scope 2 and (for certain companies) Scope 3 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 proposed climate disclosure rules have not yet been finalized, but implementation of the rules as proposed 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 current presidential administration and Congress may restrict our access to additional acreage and new leases in the U.S. Gulf of Mexico 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 consolidated 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 gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. 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, 2023, 1.7% 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 GHG 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 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 an additional limit of $450 million per occurrence ($850 million for U.S. Gulf of Mexico 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 and, 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 oil and liquids.

The issue of climate change has caused considerable attention to be directed towards initiatives to reduce global GHG emissions. The Paris Agreement and subsequent yearly "conferences of the parties" to the Paris Agreement 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 November and December 2023, the international community gathered in Dubai at the 28th Conference to the Parties on the UN Framework Convention on Climate Change (COP28), during which multiple announcements were made, including a global agreement that calls for transitioning away from fossil fuels, and a pledge by about 50 oil and gas producing countries to achieve near-zero methane emissions by 2030. In addition, the federal government could issue various executive orders that may result in additional laws, rules and regulations in the area of climate change. It is possible that the Paris Agreement, COP28, government 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 initiatives 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 exploration and production business. With or without renewable-energy subsidies, the unknown pace and strength of technological advancement of non-fossil-fuel energy sources creates uncertainty about the timing and pace of effects on our business model. The Company continually monitors the global climate change agenda initiatives and plans accordingly based on its assessment 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, 2023.

Item 1C. CYBERSECURITY

Murphy's cybersecurity environment is led by the Company's Information Technology (IT) group, which, in addition to cybersecurity matters, oversees the Company's IT infrastructure. Within the IT group, the Murphy Cybersecurity Team (MCT) is responsible for monitoring and managing security of the corporate network and enterprise systems, including developing and deploying policies, technical controls, and safety protocols and responding to security threats. 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 threats and incidents as they occur. The Chief Information Officer is a member of the IMT, and regularly provides briefings to the Chief Executive Officer, the executive leadership team, and the Audit Committee of the Board. The Audit Committee is ultimately responsible for ensuring that management has processes in place to identify and evaluate 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. 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 protection from cybersecurity threats to be a core component of its overall enterprise risk management system. Murphy's cybersecurity risk management framework consists of cyber readiness, cybersecurity governance, and risk management strategy. The cybersecurity risk management framework is incorporated into the overall enterprise risk management process through policies, procedures, periodic simulations, and constant monitoring of the cybersecurity environment for new and emerging threats. The Company also requires employees to receive 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.

Murphy utilizes industry leading technologies that focus on continuous monitoring and analytics built on machine learning and artificial intelligence to safeguard against sophisticated cyberattacks. Deployed technologies include next generation firewalls, advanced endpoint and email protection, multi-factor authentication and Managed Detection and Response.

In addition to the monitoring and detection processes for its own IT systems, Murphy also has processes in place to identify cybersecurity threats associated with third party service providers and partners; these processes include industry information sharing groups, cybersecurity notification services, vendor risk assessments, and ongoing collaboration with federal agencies.

Murphy has not experienced any material impacts to our business, operations, or reputation due to cyberattacks or other security-related incidents. However, we recognize cyber threats are constantly evolving and are committed to cultivating a culture of security, remaining vigilant and continually improving our cybersecurity environment and controls.

PART I

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages 103 to 118 and in Note D beginning on page 77.

Item 3. LEGAL PROCEEDINGS

Discussion of the Company's legal proceedings are included in Note Q beginning on page 96.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Information about our Executive Officers

Present corporate office, length of service in office and age at February 1, 2024 of 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.

Roger W. Jenkins – Age 62; Chief Executive Officer since 2013. Mr. Jenkins served as President from 2013 to 2024 and Chief Operating Officer from 2012 to 2013.

Eric M. Hambly – Age 49; President and Chief Operating Officer since February 2024. Mr. Hambly served as Executive Vice President, Operations from 2020 to 2023. He also served as Executive Vice President, Onshore from 2018 to 2020 and Senior Vice President, U.S. Onshore of Murphy Exploration & Production Company from 2016 to 2018.

Thomas J. Mireles – Age 51; Executive Vice President and 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 59; Executive Vice President, General Counsel and Corporate Secretary since February 2024. Mr. Botner served as Senior Vice President, General Counsel and Corporate Secretary from 2020 to 2023. He also served as Vice President, Law and Corporate Secretary from 2015 to 2020 and Manager, Law and Corporate Secretary from 2013 to 2015.

Daniel R. Hanchera - Age 66; 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. He also served as Vice President, Business Development and Planning of Murphy Exploration & Production Company from 2009 to 2014.

John B. Gardner – Age 55; Vice President, Marketing and Supply Chain since 2022. Mr. Gardner was Vice President and Treasurer from 2015 to 2022 and served as Treasurer from 2013 to 2015.

Leyster L. Jumawan - Age 47; Vice President, Corporate Planning and Treasurer since 2022. Mr. Jumawan was Assistant Treasurer from 2017 to 2022.

Maria A. Martinez – Age 49; Vice President, Human Resources and Administration since 2018. Ms. Martinez was Vice President, Human Resources of Murphy Exploration & Production Company from 2013 to 2018.

Meenambigai Palanivelu - Age 50; Vice President, Sustainability since 2023. Ms. Palanivelu was Director, Sustainability from 2020 to 2023. Ms. Palanivelu also served as the General Manager, Planning and Performance from 2019 to 2020 and General Manager, Finance Operating Model Program Management Office from 2017 to 2019.

Louis W. Utsch – Age 58; Vice President, Tax since 2018.

Paul D. Vaughan – Age 57, Vice President and Controller since 2022. Mr. Vaughan was Vice President and Controller, U.S., Central and South America of Murphy Exploration & Production Company from 2017 to 2022.

Kelly L. Whitley – Age 58; Vice President, Investor Relations and Communications since 2015.

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 1,974 stockholders of record as of December 31, 2023. Information on dividends per share by quarter for 2023 and 2022 are reported on page 119 of this Form 10-K report.

Issuer Purchase of Equity Securities:

The following table summarizes repurchases of our common stock occurring in the fourth quarter 2023.

Period	Total Number of Shares Purchased	Average Price Paid Per Share [1]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under Plans or Programs[2,3] *(in thousands)*
October 1 through October 31, 2023	–	$ –	–	$ 525,000
November 1 through November 30, 2023	1,154,348	$ 43.29	1,154,348	$ 475,000
December 1 through December 31, 2023	572,288	$ 43.66	572,288	$ 450,000

[1] Amounts exclude 1% excise tax and fees on share repurchases.

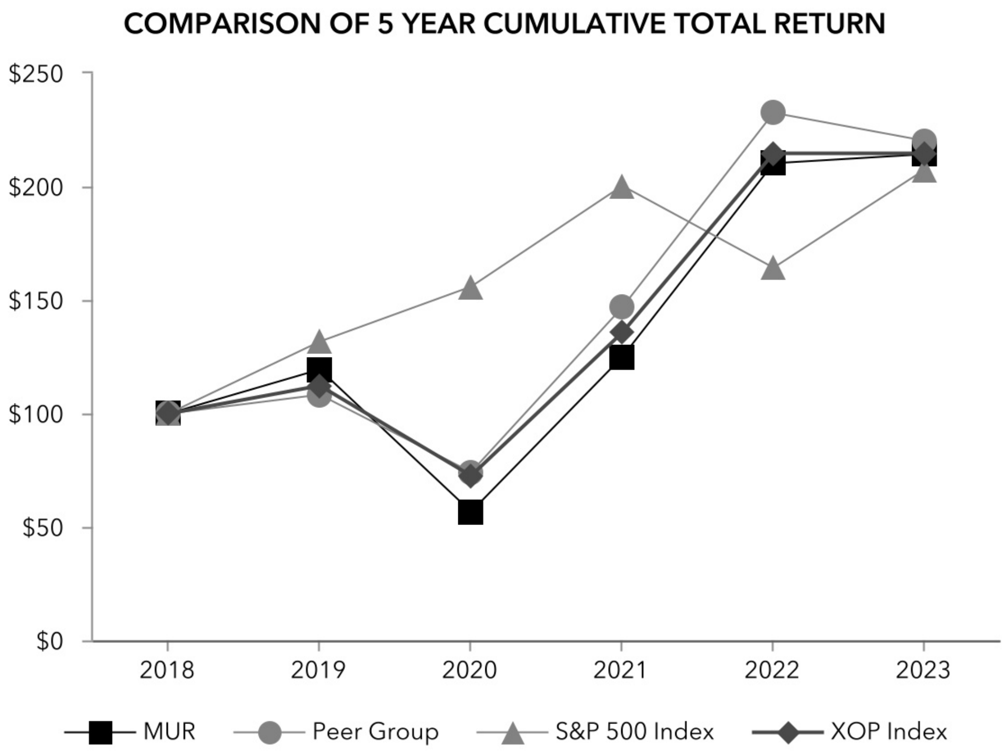
[2] In August 2022, the Board authorized an initial share repurchase program of up to $300 million of the Company's common stock. On October 30, 2023, the Company authorized an increase to the share repurchase program by an additional $300 million, bringing the total amount allowed to be repurchased under the program to $600 million. 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.

[3] Maximum approximate dollar values reported represent amounts at end of the month. During 2023, the Company repurchased 3,411,158 shares of its common stock under the share repurchase program in open-market transactions for $150.0 million, excluding taxes and fees.

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, 2018 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 gas exploration and production 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 2023 is presented in the table below. Callon Petroleum Company, Matador Resources Company and SM Energy Company were added to Murphy’s peer group in 2023 and CNX Resources Corporation was removed. 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 included:

APA Corporation
Callon Petroleum Company
Coterra Energy Inc.
Devon Energy Corporation
Hess Corporation
Kosmos Energy Ltd.
Marathon Oil Corporation
Matador Resources Company
Ovintiv Inc.
PDC Energy Inc. [1]
Range Resources Corporation
SM Energy Company
Southwestern Energy Company
Talos Energy Inc.



	2018	2019	2020	2021	2022	2023
Murphy Oil Corporation	100	119	56	125	210	214
Peer Group	100	108	74	147	233	220
S&P 500 Index	100	131	156	200	164	207
XOP Index	100	112	72	135	215	215

[1] PDC Energy Inc. was acquired in 2023 and therefore has been excluded from the above table and graph of cumulative total return.

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 2021 results and year-over-year comparisons between 2022 and 2021 are not included in this Form 10-K and can be found in Item 7 of the 2022 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 gas exploration and production company with both onshore and offshore operations and properties. The Company produces crude oil, natural gas and natural gas liquids primarily in the U.S. and Canada and explores for crude oil, natural gas and natural gas liquids 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 in MP GOM, unless otherwise noted.

Significant Company financial and operational highlights during 2023 were as follows:

- Generated net income of $661.6 million and net cash provided by operating activities of $1,748.8 million;
- Produced 193 thousand barrels of oil equivalent (BOE) per day (186 thousand excluding noncontrolling interest, NCI);
- Sanctioned the Lac Da Vang field development project in Vietnam;
- Enhanced exploration portfolio with signing production sharing contracts for five blocks in Côte d'Ivoire;
- Drilled a discovery at the Longclaw #1 operated exploration well in Green Canyon 433 in the Gulf of Mexico;
- Acquired an 8% working interest in the non-operated Zephyrus discovery in the Gulf of Mexico for a purchase price of approximately $13 million, net of closing adjustments;
- Resumed operations at non-operated Terra Nova field in offshore Canada during the fourth quarter of 2023, with production ramping up through first quarter 2024;
- Advances made under the capital allocation framework[1]:
  - Early debt retirement of approximately $500 million, a 27% debt reduction in the year
  - Repurchased shares of common stock under the share repurchase program for $150 million, excluding excise taxes, commissions and fees
  - Increased cash dividends by 10% since the fourth quarter of 2022 to $0.275 per share, or $1.10 per share annualized
- Achieved 134% (139% excluding NCI) total proved reserve replacement with year-end proved reserves of 739.5 million barrels of oil equivalent (724.0 million excluding NCI).

[1] Details of the capital allocation framework can be found as part of the Company's Form 8-K filed on August 4, 2022. On October 30, 2023, the initial share repurchase program of $300 million of the Company's common stock was increased by an additional $300 million, bringing the total amount allowed to be repurchased under the program to $600 million.

Murphy's continuing operations generate revenue by producing crude oil, natural gas liquids, and natural gas in the United States and Canada and then selling these products to customers. The Company's revenue is affected by the prices of crude oil, natural gas and natural gas liquids. In order to make a profit and generate cash in its exploration and production 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, 2023, the Company's net income from continuing operations was $725.2 million, a decrease of $415.6 million compared to 2022. Lower net income from continuing operations was largely driven by lower revenues and other income ($472.5 million), higher lease operating expenses ($105.1 million) and higher exploration expenses ($101.6 million), partially offset by lower other operating expense ($91.0 million) and lower income tax expense ($113.5 million). Lower revenues and other income resulted from overall lower pricing partially offset by overall higher sales volumes and lower losses on derivative instruments. Higher lease operating expenses were related to higher sales volumes as well as additional costs for workover and maintenance activities at Gulf of Mexico operations. Higher exploration costs were the result of dry hole expense for the Chinook #7 (Walker Ridge 425) and Oso #1 (Atwater Valley 138) exploration wells, that did not find commercial hydrocarbons in the Gulf of Mexico, the purchase of seismic data for Côte d'Ivoire, and the expensing of previously suspended exploration costs for the Cholula-1EXP well in Mexico. No losses were recorded in 2023 on derivative instruments as no fixed price derivative swaps or collar contracts were in effect during the period. Lower other expenses were due to lower contingent consideration adjustments relating to prior acquisitions in the Gulf of Mexico. Lower income tax expense was the result of lower pre-tax income.

For the year ended December 31, 2023, total hydrocarbon production was 192,640 barrels of oil equivalent per day, an increase of 10% compared to 2022. The increase was principally due to new well production volumes in the Gulf of Mexico from the Khaleesi, Mormont, Samurai field development project, new well production from Tupper Montney and lower royalty rates, partially offset by lower production volumes at other fields in the Gulf of Mexico due to additional downtime.

Results of Operations

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

(Millions of dollars)	**2023**	2022	2021
Exploration and production			
United States	**$ 905.1**	$ 1,521.9	$ 766.3
Canada	**41.6**	134.2	(16.1)
Other International	**(65.5)**	(77.0)	(33.5)
Total exploration and production	**881.2**	1,579.1	716.7
Corporate and other	**(156.0)**	(438.3)	(668.0)
Income from continuing operations	**725.2**	1,140.8	48.7
Loss from discontinued operations [1]	**(1.5)**	(2.1)	(1.2)
Net income including noncontrolling interest	**723.7**	1,138.7	47.5
Net income attributable to noncontrolling interest	**62.1**	173.7	121.2
Net income attributable to Murphy	**$ 661.6**	$ 965.0	$ (73.7)

[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: 2023 vs 2022

The following section of Exploration and Production (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 are summarized income statements for E&P continuing operations.

(Millions of dollars)	**2023**	2022	2021
Revenues and other income			
Revenue from production	**$ 3,376.6**	$ 4,038.5	$ 2,801.2
Sales of purchased natural gas	**72.2**	181.7	–
Other income	**8.0**	26.7	17.5
Total revenues and other income	**3,456.8**	4,246.9	2,818.7
Cost and Expenses			
Lease operating expenses	**784.4**	679.3	539.5
Severance and ad valorem taxes	**42.8**	57.0	41.2
Transportation, gathering and processing	**233.0**	212.7	187.0
Costs of purchased natural gas	**51.7**	172.0	–
Depreciation, depletion and amortization	**850.5**	763.9	782.1
Impairments of assets	**–**	–	189.3
Accretion of asset retirement obligations	**46.0**	46.2	46.6
Total exploration expenses	**234.8**	133.1	69.0
Selling and general expenses	**37.7**	44.5	43.6
Other	**56.9**	141.8	31.0
Results of operations before taxes	**1,119.0**	1,996.4	889.4
Income tax provisions	**237.8**	417.3	172.7
Results of operations (excluding Corporate segment) [1]	**$ 881.2**	$ 1,579.1	$ 716.7

[1] Includes results attributable to a noncontrolling interest in MP GOM.

Pricing

The following table contains the weighted average sales prices for the three years ended December 31, 2023.

(Weighted average sales prices)	**2023**	2022	2021
Crude oil and condensate – dollars per barrel			
United States - Onshore	**$ 76.96**	$ 96.00	$ 66.90
United States - Offshore [1]	**77.38**	94.21	66.93
Canada - Onshore [2]	**72.84**	89.88	61.79
Canada - Offshore [2]	**84.20**	107.47	71.39
Other [2]	**86.60**	94.37	69.21
Natural gas liquids – dollars per barrel			
United States - Onshore	**$ 19.69**	$ 33.85	$ 26.97
United States - Offshore [1]	**21.94**	36.01	29.14
Canada - Onshore [2]	**35.87**	55.65	40.18
Natural gas – dollars per thousand cubic feet			
United States - Onshore	**$ 2.26**	$ 6.04	$ 3.83
United States - Offshore [1]	**2.78**	6.97	3.67
Canada - Onshore [2]	**2.06**	2.76	2.43

[1] Prices include the effect of 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, 2023.

(Average price for the period)	**2023**	2022	2021
Oil and NGLs			
WTI ($/BBL)	**$ 77.62**	$ 94.23	$ 67.91
Natural gas			
NYMEX ($/MMBTU)	**2.53**	6.38	3.84
AECO (C$/MCF)	**2.64**	5.31	3.63

Production Volumes

The following table contains hydrocarbons produced during the three years ended December 31, 2023. For further discussion on volumes, please see Revenues from Production section on page 37.

(Barrels per day unless otherwise noted)	**2023**	2022	2021
Net crude oil and condensate			
United States - Onshore	**24,070**	24,437	25,655
United States - Offshore [1]	**73,473**	65,411	60,717
Canada - Onshore	**2,937**	4,005	5,312
Canada - Offshore	**3,020**	2,812	3,765
Other	**250**	700	256
Total net crude oil and condensate	**103,750**	97,365	95,705
Net natural gas liquids			
United States - Onshore	**4,617**	5,181	5,092
United States - Offshore [1]	**5,924**	4,597	4,176
Canada - Onshore	**681**	903	1,117
Total net natural gas liquids	**11,222**	10,681	10,385
Net natural gas – thousands of cubic feet per day			
United States - Onshore	**25,863**	29,050	28,565
United States - Offshore [1]	**70,239**	63,380	61,240
Canada - Onshore	**369,906**	310,230	277,790
Total net natural gas	**466,008**	402,660	367,595
Total net hydrocarbons - including NCI [2,3]	**192,640**	175,156	167,356
Noncontrolling interest			
Net crude oil and condensate – barrels per day	**(6,210)**	(7,452)	(8,623)
Net natural gas liquids – barrels per day	**(220)**	(280)	(303)
Net natural gas – thousands of cubic feet per day	**(2,089)**	(2,468)	(3,236)
Total noncontrolling interest [2,3]	**(6,778)**	(8,143)	(9,465)
Total net hydrocarbons - excluding NCI [2,3]	**185,862**	167,013	157,891
Estimated total proved net hydrocarbon reserves - million equivalent barrels [3,4]	**739.5**	715.4	716.9

[1] Includes net volumes attributable to a noncontrolling interest in MP GOM.

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

[3] NCI – noncontrolling interest in MP GOM.

[4] December 31, 2023, 2022 and 2021, include 15.5 MMBOE, 18.2 MMBOE and 18.4 MMBOE, respectively, relating to noncontrolling interest.

Sales Volumes

The following table contains hydrocarbons sold during the three years ended December 31, 2023. For further discussion on volumes, please see Revenues from Production section on page 37.

(Barrels per day unless otherwise noted)	**2023**	2022	2021
Net crude oil and condensate			
United States - Onshore	**24,070**	24,437	25,655
United States - Offshore [1]	**73,373**	64,840	60,544
Canada - Onshore	**2,937**	4,005	5,312
Canada - Offshore	**2,559**	3,002	3,559
Other	**349**	663	195
Total net crude oil and condensate	**103,288**	96,947	95,265
Net natural gas liquids			
United States - Onshore	**4,617**	5,181	5,092
United States - Offshore [1]	**5,924**	4,597	4,176
Canada - Onshore	**681**	903	1,117
Total net natural gas liquids	**11,222**	10,681	10,385
Net natural gas – thousands of cubic feet per day			
United States - Onshore	**25,863**	29,050	28,565
United States - Offshore [1]	**70,239**	63,380	61,240
Canada - Onshore	**369,906**	310,230	277,790
Total net natural gas	**466,008**	402,660	367,595
Total net hydrocarbons - including NCI [2,3]	**192,178**	174,738	166,916
Noncontrolling interest			
Net crude oil and condensate – barrels per day	**(6,200)**	(7,369)	(8,605)
Net natural gas liquids – barrels per day	**(220)**	(280)	(303)
Net natural gas – thousands of cubic feet per day	**(2,089)**	(2,468)	(3,236)
Total noncontrolling interest [2,3]	**(6,768)**	(8,060)	(9,447)
Total net hydrocarbons - excluding NCI [2,3]	**185,410**	166,678	157,469

[1] Includes net volumes attributable to a noncontrolling interest in MP GOM.

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

[3] NCI – noncontrolling interest in MP GOM.

Revenues from Production

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

(Millions of dollars)		**2023**		2022		2021
Revenues from production						
United States - Oil	**$**	**2,748.5**	$	3,085.9	$	2,105.2
United States - Natural gas liquids		**80.6**		124.4		94.6
United States - Natural gas		**92.7**		225.3		121.7
Canada - Oil		**156.7**		249.2		212.5
Canada - Natural gas liquids		**8.9**		18.3		16.4
Canada - Natural Gas		**278.2**		312.6		245.9
Other - Oil		**11.0**		22.8		4.9
Total revenues from production	**$**	**3,376.6**	$	4,038.5	$	2,801.2

Revenues from production in 2023 decreased by $661.9 million compared to 2022. Lower revenues from U.S. E&P was primarily attributable to lower realized prices in 2023 compared to 2022, partially offset by higher overall sales volumes from the Gulf of Mexico. Higher sales volumes were driven by new well performance from the Khaleesi, Mormont, Samurai field development project, and were partially offset by lower sales volumes at other fields. Lower revenues from Canadian E&P was primarily attributable to lower realized prices and lower sales volumes at Kaybob Duvernay partially offset by higher sales volumes at Tupper Montney. Lower sales volumes at Kaybob Duvernay were primarily due to the divestment of certain non-core operated Kaybob Duvernay assets and all of the non-operated Placid Montney assets, as well as natural declines. Higher sales volumes at Tupper Montney were the result of new wells coming online in 2023, improved well performance, and lower royalty rates.

Natural gas is purchased and subsequently sold to third parties in order to provide operational flexibility and cost mitigation for transportation commitments. Sales of purchase natural gas is included in "Total revenues and other income" and cost to purchase natural gas is included in "Costs and Expenses" in the summarized income statements for E&P continuing operations on page 34.

Other Income

Other income was $8.0 million in 2023, a decrease of $18.7 million compared to 2022. Lower other income was primarily the result of a gain on sale of the Thunder Hawk field in the third quarter of 2022.

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)		
	2023	2022	2021	**2023**	2022	2021
Lease operating expenses						
United States – Onshore	**$ 150.3**	$ 137.6	$ 115.7	**$ 12.48**	$ 10.94	$ 8.93
United States – Offshore	**480.4**	385.1	290.7	**14.46**	13.19	10.63
Canada – Onshore	**140.3**	139.5	119.4	**5.89**	6.75	6.20
Canada – Offshore	**11.5**	15.6	16.9	**12.30**	14.20	13.04
Other	**1.9**	1.5	(3.2)	**14.94**	6.25	(44.94)
Total lease operating expenses	**$ 784.4**	$ 679.3	$ 539.5	**$ 11.18**	$ 10.65	$ 8.86
Transportation, gathering and processing						
United States – Onshore	**$ 12.7**	$ 18.4	$ 26.1	**$ 1.05**	$ 1.47	$ 2.02
United States – Offshore	**144.3**	123.8	100.4	**4.34**	4.24	3.67
Canada – Onshore	**72.2**	65.3	57.4	**3.03**	3.16	2.98
Canada – Offshore	**3.8**	5.2	3.1	**4.12**	4.76	2.36
Total transportation, gathering and processing	**$ 233.0**	$ 212.7	$ 187.0	**$ 3.32**	$ 3.34	$ 3.07

Lease operating expenses and transportation, gathering and processing expenses in 2023 increased by $105.1 million and $20.3 million, respectively, compared to 2022. Higher lease operating expenses and increased transportation, gathering and processing expenses from U.S. E&P were primarily due to increased sales volumes and higher operating expenses for additional workover and maintenance activities from the Gulf of Mexico operations.

Depreciation, Depletion and Amortization Expense

The Company's depreciation, depletion and amortization expense by geographic area were as follows:

	(Millions of dollars)			(Dollars per equivalent barrel)		
	2023	2022	2021	**2023**	2022	2021
Depreciation, depletion and amortization expense						
United States – Onshore	**$ 316.7**	$ 321.4	$ 356.4	**$ 26.29**	$ 25.55	$ 27.50
United States – Offshore	**389.3**	295.6	260.1	**11.72**	10.12	9.51
Canada – Onshore	**133.4**	128.1	147.2	**5.60**	6.20	7.64
Canada – Offshore	**8.8**	13.4	16.6	**9.47**	12.25	12.80
Other	**2.3**	5.4	1.8	**18.05**	22.19	26.78
Total depreciation, depletion and amortization expense	**$ 850.5**	$ 763.9	$ 782.1	**$ 12.12**	$ 11.98	$ 12.84

Depreciation, depletion and amortization expense (DD&A) in 2023 increased by $86.6 million compared to 2022. Higher DD&A was primarily the result of higher sales volumes and higher rates from the Gulf of Mexico. DD&A from Canadian E&P increased at Tupper Montney due to higher sales volumes and higher rates, substantially offset by lower sales volumes and lower rates at Kaybob Duvernay.

Exploration Expenses

The Company’s exploration expenses were as follows:

(Millions of dollars)	**2023**	2022	2021
Exploration expenses			
Dry holes and previously suspended exploration costs	**$ 169.8**	$ 82.1	$ 17.3
Geological and geophysical	**26.1**	10.4	11.8
Other exploration	**28.0**	27.3	21.0
Undeveloped lease amortization	**10.9**	13.3	18.9
Total exploration expenses	**$ 234.8**	$ 133.1	$ 69.0

Exploration expenses in 2023 increased by $101.7 million compared to 2022. Higher dry holes and previously suspended exploration costs primarily relate to the dry hole expense of Chinook #7 (Walker Ridge 425) and Oso #1 (Atwater Valley 138) exploration wells in the Gulf of Mexico, which encountered non-commercial hydrocarbons, and the write-off of previously suspended exploration costs for the Cholula-1EXP well in Mexico. Higher geological and geophysical expenses in 2023 relate to the purchased seismic data for Côte d’Ivoire. In 2022, dry holes and previously suspended exploration costs primarily relate to expensed costs for the Cutthroat-1 exploration well in block SEAL-M-428 in offshore Brazil and the Tulum-1EXP exploration well in Block 5 in offshore Mexico that did not encounter commercial hydrocarbons.

Other Expenses

Other expenses were $56.9 million in 2023, a decrease of $84.9 million compared to 2022. Other expenses were lower primarily due to a lower unfavorable contingent consideration adjustment of $7.1 million in 2023 (2022: $78.3 million), as a result of reaching contractual thresholds or time limitations that ended in 2022 (see Note O). In addition, there were lower asset retirement adjustments related to non-producing fields of $18.2 million in 2023 (2022: $35.0 million).

Income Taxes

Income taxes were $237.8 million in 2023, a decrease of $179.5 million compared to 2022. Lower income taxes were primarily the result of lower pre-tax income (see Note H).

Corporate: 2023 vs 2022

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

Corporate activities reported a loss of $156.0 million in 2023, a favorable variance of $282.2 million compared to 2022. The favorable variance was primarily due to no current period losses on derivative instruments in 2023, compared to a loss for the same period in 2022 ($320.4 million) and lower interest expense ($38.6 million), partially offset by lower income tax benefits ($66.0 million) and foreign exchange loss of $10.7 million in 2023 compared to foreign exchange gain of $23.0 million in 2022. Interest charges are lower in 2023 primarily due to lower overall debt levels as the Company reduced debt by $498.2 million and $647.7 million during 2023 and 2022, respectively. During 2023 and as of December 31, 2023, the Company did not enter into or have any fixed price derivative swaps or collar contracts outstanding. Lower income tax benefit was a result of lower pre-tax losses.

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 senior unsecured RCF. The Company’s liquidity requirements consist primarily of capital expenditures, debt maturity, retirement and interest payments, working capital requirements, dividend payments, and, as applicable, share repurchases.

Cash Flows

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

(Millions of dollars)	**2023**	2022	2021
Net cash provided by (required by):			
Net cash provided by continuing operations activities	**$ 1,748.8**	$ 2,180.2	$ 1,422.2
Net cash required by investing activities	**(998.7)**	(1,109.4)	(417.7)
Net cash required by financing activities	**(923.7)**	(1,081.6)	(794.5)
Net cash required by discontinued operations	**–**	(14.5)	–
Effect of exchange rate changes on cash and cash equivalents	**(1.2)**	(3.9)	0.6
Net (decrease) increase in cash and cash equivalents	**$ (174.8)**	$ (29.2)	$ 210.6

Cash Provided by Continuing Operations Activities

Net cash provided by continuing operations activities in 2023 was $431.4 million lower compared to 2022. The decrease was primarily attributable to lower revenue from production ($661.9 million), higher payments of contingent consideration related to prior Gulf of Mexico acquisitions ($139.6 million), higher lease operating expenses ($105.1 million) and timing of working capital settlements ($33.6 million), partially offset by lower realized losses on derivative instruments ($535.2 million). Payments of contingent consideration are shown both in “Operating Activities” and “Financing Activities” in the Company’s Consolidated Statements of Cash Flows; amounts considered as financing activities are those amounts paid up to the original estimated contingent consideration liability included in the purchase price allocation, at the time of acquisition. Any contingent consideration paid above the original estimated liability, included in the purchase price, are considered operating activities. During 2023, the Company paid a total of $199.8 million in contingent consideration, of which $139.6 million is shown in “Operating Activities” and $60.2 million is shown in “Financing Activities” in the Company’s Consolidated Statements of Cash Flows. As of the end of the second quarter of 2023, the Company had no further obligation payable for contingent consideration relating to prior Gulf of Mexico acquisitions. See Note O for further details.

The total reductions of operating cash flows for interest paid (which excludes debt redemption costs reported in “Financing Activities”) during the two years ended December 31, 2023, and 2022 were $108.9 million and $150.0 million, respectively. Lower cash interest paid in 2023 was primarily due to the early redemption, in whole or in part, of the 5.75% senior notes due 2025 (2025 Notes), the 5.875% senior notes due 2027 (2027 Notes), the 6.375% senior notes due 2028 (2028 Notes), and the 7.050% senior notes due 2029 (2029 Notes) in the aggregate amount of $498.2 million.

Cash Required by Investing Activities

Net cash required by investing activities in 2023 was $110.7 million lower compared to 2022. The decrease was primarily due to the proceeds from the sale of certain non-core operated Kaybob Duvernay assets and all of the non-operated Placid Montney assets ($102.9 million) and lower acquisition capital ($93.0 million), partially offset by higher property additions and dry hole costs ($80.6 million).

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)	**2023**	2022	2021
Property additions and dry hole costs per cash flow statements [1]	**$ 1,066.0**	$ 985.5	$ 650.2
Geophysical and other exploration expenses	**46.0**	30.6	26.9
Acquisition of oil properties per the cash flow statements [1]	**35.6**	128.5	20.3
Capital expenditure accrual changes and other	**(9.5)**	38.6	(3.9)
Property additions King's Quay Floating Production System (FPS) per cash flow statements	**–**	–	17.7
Total capital expenditures	**$ 1,138.1**	$ 1,183.2	$ 711.2

[1] Certain prior-period amounts have been reclassified to conform to the current period presentation.

Total accrual basis capital expenditures are shown below.

	Year Ended December 31,		
(Millions of dollars)	**2023**	2022	2021
Capital Expenditures			
Exploration and production	**$ 1,114.0**	$ 1,161.5	$ 690.1
Corporate	**24.1**	21.7	21.1
Total capital expenditures	**1,138.1**	1,183.2	711.2
Total capital expenditures excluding proved property acquisitions	**1,111.0**	1,054.7	711.2
Total capital expenditures excluding proved property acquisitions and NCI	**$ 1,040.8**	$ 1,028.8	$ 688.2

Lower capital expenditures in 2023 compared to 2022 were primarily attributable to lower development expenditures at the Khaleesi, Mormont, Samurai field development project, lower spend at the Kodiak and Lucius fields and lower acquisition capital, partially offset by higher exploratory drilling and higher development expenditures at the Dalmatian and St. Malo fields. Capital expenditures in 2023 primarily relate to development drilling and field development activities in the Eagle Ford Shale ($361.5 million); development activities in the Gulf of Mexico, primarily related to St. Malo, Dalmatian, Samurai and Marmalard fields ($310.1 million); development drilling and field development activities at the Tupper Montney field ($142.0 million); field development at Terra Nova for the asset life extension project ($44.7 million); and total exploration costs of $214.3 million. Exploration costs were primarily for activities at Chinook #7 (Walker Ridge 425), Oso #1 (Atwater Valley 138) and Longclaw #1 (Green Canyon 433) within the Gulf of Mexico and activities at Côte d’Ivoire. Costs of $169.8 million primarily associated with Chinook #7 (Walker Ridge 425) and Oso #1 (Atwater Valley 138) were expensed to dry hole costs in 2023 as the Company determined there were non-commercial hydrocarbons present.

Cash Required by Financing Activities

Net cash required by financing activities in 2023 decreased by $157.9 million compared to 2022. In 2023, cash used in financing activities was principally for the redemption of the remaining $248.7 million principal outstanding on its 2025 Notes and the tendering of $249.5 million of its 2027 Notes, 2028 Notes and 2029 Notes. In addition, the Company repurchased common shares ($150.0 million, excluding accrued excise tax), paid contingent consideration related to prior Gulf of Mexico acquisitions ($60.2 million) as discussed in the ‘Cash Provided by Continuing Operating Activities’ section, paid cash dividends to shareholders of $1.10 per share ($171.0 million), and distributed funds to the noncontrolling interest in the Gulf of Mexico ($29.4 million).

Liquidity

At December 31, 2023, the Company had approximately $1.1 billion of liquidity consisting of $317.1 million in cash and cash equivalents and $796.2 million available on its committed senior unsecured RCF with a major banking consortium.

The Company's $800 million senior unsecured RCF expires in November 2027 and as of December 31, 2023, the Company had no outstanding borrowings under the RCF and $3.8 million of outstanding letters of credit, which reduce the borrowing capacity of the senior unsecured RCF. Borrowings under the RCF are subject to certain interest rates, please refer to Note F for further details. At December 31, 2023, the interest rate in effect on borrowings under the facility would have been 7.70%. At December 31, 2023, the Company was in compliance with all covenants related to the RCF.

Cash and invested cash are maintained in several operating locations outside the U.S. As of December 31, 2023, cash and cash equivalents held outside the U.S. included U.S dollar equivalents of approximately $148.9 million (2022: $147.7 million), the majority of which was held in Canada ($105.2 million) and Mexico ($18.1 million). In addition, approximately $9.6 million and $8.3 million of cash was held in the U.K. and Spain, 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 United States.

Working Capital

(Millions of dollars)	**December 31, 2023**	December 31, 2022
Working capital		
Total current assets	**$ 752.2**	$ 972.3
Total current liabilities	**846.5**	1,257.8
Net working capital liability	**$ (94.3)**	$ (285.5)

As of December 31, 2023, net working capital had a favorable increase of $191.2 million compared to December 31, 2022. The favorable increase was primarily attributable to lower other accrued liabilities ($302.8 million) and lower accounts payable ($96.9 million), partially offset by lower accounts receivable ($47.2 million) and a lower cash balance ($174.9 million). Lower accrued liabilities were primarily due to payments made for contingent consideration obligations from prior Gulf of Mexico acquisitions, payments for abandonment activities and incentive payments made in 2023. Lower accounts payable were primarily due to decreases in unrealized losses on derivative instruments (commodity price swaps and collars), decreases in royalties payable due to lower revenues, payments made for abandonment activities and drilling and completions activities. Lower unrealized losses on derivative instruments were as a result of no commodity derivative instrument contracts entered into or outstanding during 2023. Lower accounts receivable were primarily due to lower sales volumes for crude oil and natural gas liquids and lower pricing received for all crude oil, natural gas liquids and natural gas.

Capital Employed

A summary of capital employed as of December 31, 2023 and 2022 follows.

	December 31, 2023		December 31, 2022	
(Millions of dollars)	**Amount**	**%**	Amount	%
Capital employed				
Long-term debt	**$ 1,328.4**	**19.9 %**	$ 1,822.4	26.7 %
Murphy shareholders' equity	**5,362.8**	**80.1 %**	4,994.8	73.3 %
Total capital employed	**$ 6,691.2**	**100.0 %**	$ 6,817.2	100.0 %

As of December 31, 2023, long-term debt decreased by $494.0 million compared to December 31, 2022, as a result of the redemption and early redemption of, in whole or in part, the 2025 Notes, 2027 Notes, 2028 Notes, and 2029 Notes. The fixed-rate notes had a weighted average maturity of 8.1 years and a weighted average coupon of 6.2%.

Murphy’s shareholders’ equity increased by $368.0 million in 2023 primarily due to net income earned ($661.6 million), partially offset by cash dividends paid ($171.0 million) and shares repurchased ($150.0 million, including excise tax). A summary of transactions in stockholders’ equity accounts is presented in the Consolidated Statements of Stockholders’ Equity on page 69 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 2023, compared to 2022 are discussed below.

Property, plant and equipment, net of depreciation, decreased $2.8 million principally due to DD&A expense ($861.6 million) and divestment of certain non-core operated Kaybob Duvernay assets and all of the non-operated Placid Montney assets, substantially offset by capital expenditures in the year and foreign exchange rates applicable for the Canadian assets. Capital expenditures are discussed above in the ‘Cash Required for Investing Activities’ section.

Murphy had commitments for capital expenditures of approximately $209.8 million at December 31, 2023 (2022: $282.4 million). This amount includes $75.1 million for approved expenditures for capital projects relating to non-operated interests in deepwater U.S. Gulf of Mexico, principally at St. Malo ($61.7 million), non-operated Canada interests, mainly offshore ($11.6 million), non-operated Lucius ($13.3 million) and non-operated Eagle Ford Shale ($11.8 million).

Operating lease assets decreased $201.2 million principally due to depreciation on these assets.

Deferred Income tax assets decreased by $117.5 million as a result of the decrease in the U.S. net operating loss carryforward from $2.1 billion at year-end 2022 to $1.7 billion at year-end 2023.

Long term asset retirement obligations increased $86.8 million primarily due to accretion and additions and revisions related to Gulf of Mexico and Eagle Ford Shale operations.

Non-current operating lease liabilities decreased $190.8 million primarily due to 2023 annual payments reducing operating lease liabilities for drilling rig and vessel commitments.

Deferred income tax liabilities increased $61.7 million due to capital related tax deductions.

Other Key Performance Metrics

The Company uses other operational performance and income metrics to review operational performance. Management uses adjusted net income, EBITDA and adjusted EBITDA internally to evaluate the Company's operational performance and trends between periods and relative to its industry competitors. Adjusted net income also excludes 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 and are non-GAAP financial measures and should not be considered a substitute for net income (loss) or cash provided by operating activities as determined in accordance with GAAP.

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

	Year Ended December 31,		
(Millions of dollars)	**2023**	2022	2021
Net income attributable to Murphy (GAAP) [1]	**$ 661.6**	$ 965.0	$ (73.7)
Discontinued operations loss	**1.5**	2.1	1.2
Net income from continuing operations attributable to Murphy	**663.1**	967.1	(72.5)
Adjustments [2]:			
Write-off of previously suspended exploration wells	**17.1**	22.7	–
Asset retirement obligation losses (gains)	**16.9**	30.8	(71.8)
Foreign exchange loss (gain)	**10.9**	(23.0)	(1.0)
Mark-to-market loss on contingent consideration	**7.1**	78.3	63.2
Mark-to-market (gain) loss on derivative instruments	**–**	(214.7)	112.1
(Gain) on sale of assets	**–**	(14.5)	–
Early redemption of debt cost	**–**	10.3	43.9
Impairment of assets	**–**	–	196.3
Tax benefits on investments in foreign areas	**–**	–	(8.9)
Charges related to Kings Quay transaction	**–**	–	4.9
Unutilized rig charges	**–**	–	8.7
Total adjustments, before taxes	**52.0**	(110.1)	347.4
Income tax (benefit) expense related to adjustments	**(6.4)**	23.8	(75.2)
Total adjustments after taxes	**45.6**	(86.3)	272.2
Adjusted net income from continuing operations attributable to Murphy (Non-GAAP)	**$ 708.7**	$ 880.8	$ 199.7
Net income from continuing operations per average diluted share (GAAP)	**$ 4.23**	$ 6.14	$ (0.47)
Adjusted net income from continuing operations per average diluted share (Non-GAAP)	**$ 4.52**	$ 5.59	$ 1.29

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

2 Certain prior-period amounts have been reclassified to conform to the current period presentation.

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

(Millions of dollars)	Year Ended December 31, 2023	2022	2021
Net (loss) income attributable to Murphy (GAAP) [1]	**$ 661.6**	$ 965.0	$ (73.7)
Income tax expense	**195.9**	309.5	(5.9)
Interest expense, net	**112.4**	150.8	221.8
Depreciation, depletion and amortization expense [2]	**836.7**	748.2	760.6
EBITDA attributable to Murphy (Non-GAAP)	**1,806.6**	2,173.5	902.8
Accretion of asset retirement obligations [2]	**41.0**	40.9	41.1
Write-off of previously suspended exploration well	**17.1**	22.7	–
Asset retirement obligation loss (gain)	**16.9**	30.8	(71.8)
Foreign exchange loss (gain)	**10.8**	(23.0)	(1.0)
Mark-to-market loss gain on contingent consideration	**7.1**	78.3	63.2
Mark-to-market (gain) loss on derivative instruments	**–**	(214.7)	112.1
Discontinued operations loss	**1.5**	2.1	1.2
Gain on sale of assets [2]	**–**	(14.5)	–
Impairment of assets [2]	**–**	–	196.3
Unutilized rig charges	**–**	–	8.7
Adjusted EBITDA attributable to Murphy (Non-GAAP)	**$ 1,901.0**	$ 2,096.1	$ 1,252.6

[1] Excludes amounts attributable to a noncontrolling interest in MP GOM.

[2] Depreciation, depletion and amortization expense, impairment of assets, loss (gain) on sale of sale of assets and accretion of asset retirement obligations used in the computation of adjusted EBITDA exclude the portion attributable to the noncontrolling interest.

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, 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 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 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 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 10.

Climate Change and Emissions

The world’s population and standard of living is 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 core elements. The TCFD was created by the Financial Stability Board to focus on climate-related financial disclosures to improve and increase reporting of climate-related financial information. Murphy’s disclosures related to its alignment with the TCFD are included in the Company’s 2023 Sustainability Report issued on August 2, 2023, which is not incorporated by reference hereto.

Other Matters

Impact of inflation – In 2023, many countries worldwide continued to experience a rise in inflation, including countries where the Company operates (this follows a sustained period of relatively low inflation prior to 2021). In the U.S., inflation continued as a result of ongoing supply constraints and increasing demand for goods and services as countries continue their recovery from the COVID-19 pandemic. The Company’s revenues, capital and operating costs are influenced to a larger extent by specific price changes in the oil and 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+ 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 partly protected from the increasing 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-increasing efficient manner to mitigate possible inflationary pressures in our business.

Natural gas prices are also affected by supply and demand, which are often affected by the weather and by the fact that delivery of natural gas can be restricted to specific geographic areas. Natural gas demand is also impacted by demand driven by lower carbon emissions and a view that natural gas is one option to transition from higher carbon emitting fuels.

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 obligations. 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 crude oil, natural gas liquids and natural gas are presented on pages 103 to 112 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 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, 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.

See further discussion of proved reserves and changes in proved reserves during the three years ended December 31, 2023 beginning on pages 4 and 103 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 Sheet 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 future 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.

There were no impairments recognized in 2023 or 2022.

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 reduce 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, 2023 the Company had a U.S. deferred tax asset associated with net operating losses of $357.5 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 crude oil and condensate, NGLs and natural gas, (b) estimated reserves for crude oil and condensate, NGLs 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, 2023, the Company has used a weighted average discount rate of 5.15% at year-end 2023 for the primary U.S. plans. This weighted average discount rate is 0.3% 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 8.00% for the primary U.S. plan, it 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 2024 are expected to be $0.7 million higher than in 2023 primarily due to the increase in the benefit obligations at December 31, 2023 compared to the prior year, which increases the interest cost recognized in net periodic benefit costs. Cash contributions to all plans are anticipated to be $2.9 million higher in 2024.

In 2023, the Company paid $37.5 million into various retirement plans and $2.0 million into postretirement plans. In 2024, the Company is expecting to fund payments of approximately $38.0 million into various retirement plans and $4.4 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 2023 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**	2024	2025 - 2026	2027 - 2028	After 2028
Debt, excluding interest	**$ 1,334.9**	$ –	$ –	$ 815.4	$ 519.5
Operating leases and other leases [1]	**1,019.3**	245.7	148.4	125.4	499.8
Capital expenditures, drilling rigs and other [2]	**1,289.6**	434.4	264.2	197.9	393.1
Other long-term liabilities, including debt interest [3]	**2,379.0**	98.9	197.6	139.4	1,943.1
Total	**$ 6,022.8**	$ 779.0	$ 610.2	$ 1,278.1	$ 3,355.5

[1] Other leases refers to a finance lease in Brunei (see Note T).

[2] Capital expenditures, drilling rigs and other includes $51.6 million, $11.8 million, $11.6 million and $4.0 million, in 2024 for approved capital projects in non-operated interests in U.S. Gulf of Mexico, U.S. Onshore, Canada Offshore and Other Foreign Offshore, respectively. Capital expenditures, drilling rigs and other includes $23.5 million in 2025 for approved capital projects in non-operated interests in U.S. Gulf of Mexico.

Also includes $74.6 million (2024), $145.3 million (2025 - 2026), $140.2 million (2027 - 2028) and $308.1 million (After 2028) for pipeline transportation commitments in Canada.

Also includes $4.1 million (2024), $7.7 million (2025 - 2026), $7.7 million (2027 - 2028) and $22.5 million (After 2028) for long term take or pay commitments relating to natural gas processing in Canada.

[3] Other long-term liabilities, including debt interest, includes future cash outflows for asset retirement obligations.

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 $200.6 million as of December 31, 2023.

Material off-balance sheet arrangements – Certain U.S. transportation contracts require minimum monthly payments through 2045, while Onshore Canada 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 gas industry is impacted by global commodity pricing and 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 discussing revenues, on page 37, lower average crude oil price during in 2023 directly impacted the Company’s product sales revenue.

As of close on February 21, 2024, forward price curves for existing forward contracts for the remainder of 2024 and 2025 are shown in the table below:

	2024	2025
WTI ($/BBL)	75.63	70.84
NYMEX ($/MMBTU)	2.41	3.38
AECO (US$ Equivalent/MCF)	1.39	2.38

In 2023, liquids from continuing operations represented approximately 60% of total hydrocarbons produced on an energy equivalent basis. In 2024, the Company’s ratio of hydrocarbon production represented by liquids is expected to be 59%. If the prices for crude oil and natural gas are lower in 2024 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 2024 to be between 187,100 and 195,100 barrels of oil equivalent per day (including noncontrolling interest of 7,100 BOEPD). If significant price declines occur, the Company will review the option of production curtailments to avoid incurring losses on certain produced barrels.

Similar to the overall inflation and higher interest rates in the wider economy, the oil and gas industry and the Company are observing 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, 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 2024 is expected to be between $920 million and $1,020 million, excluding noncontrolling interest. 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 2024 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 framework designed to allow for additional shareholder returns and debt reduction. Details of the framework can be found in the “Capital Allocation Framework” section of the Company’s Form 8-K filed on August 4, 2022. During 2023, the Board authorized a $300 million increase to the original share repurchase program announced in the Capital Allocation Framework, bringing the total amount allowed to be repurchased under the program to $600 million. As of December 31, 2023, the Company has $450 million remaining available to repurchase.

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 revolving credit facility (see Note F).

As of February 21, 2024, the Company has entered into forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

Area	Commodity	Type	Volumes (MMcf/d)	Price/MCF	Remaining Period Start Date	Remaining Period End Date
Canada	Natural Gas	Fixed price forward sales	162	C$2.39	1/1/2024	12/31/2024
Canada	Natural Gas	Fixed price forward sales	25	US$1.98	1/1/2024	10/31/2024
Canada	Natural Gas	Fixed price forward sales	15	US$1.98	11/1/2024	12/31/2024

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”, “expressed confidence”, “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 decisions 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 ESG (environmental/social/governance) matters, make capital expenditures or 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 gas industry, including supply/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 market of health pandemics such as COVID-19 and related government responses; other natural hazards impacting our operations or markets; any other deterioration in our business, markets or prospects; any failure to obtain necessary regulatory approvals; 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. 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 15 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. Murphy Oil Corporation undertakes no duty to publicly update or revise any forward-looking statements.

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.

There were no outstanding crude oil derivative contracts as of December 31, 2023.

There were no derivative foreign exchange contracts in place as of December 31, 2023.

At December 31, 2023, long-term debt was $1,328.4 million. The fixed-rate notes have a weighted average coupon of 6.2%.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 65 through 120 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 Murphy 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.

Based on their evaluation, with the participation of the Company’s management, as of December 31, 2023, 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, 2023. 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, 2023 and their report is included on page 64 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 2023 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, 2023, 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

None

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 8, 2024 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 www.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 Fwy, 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.

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 8, 2024 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 revised 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 10.29 to this Form 10-K report and as of December 31, 2023, 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 8, 2024 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 8, 2024 under the caption "Election of Directors".

Item 14. PRINCIPAL ACCOUNTING 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 8, 2024 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.

Financial Statement Schedules

All other 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.

PART IV

3. **Exhibits** – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are considered furnished rather than filed, 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
2.4	Share Sale and Purchase Agreement between Canam Offshore Limited and PTTEP HK Offshore Limited for the sale and purchase of the entire issued share capital of Murphy Sarawak Oil Co., Ltd. and Murphy Sabah Oil Co., Ltd., dated March 21, 2019	Exhibit 10.3 to Form 10-Q filed May 2, 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	Indenture dated as of May 4, 1999 between Murphy Oil Corporation and SunTrust Bank, Nashville, N.A., as trustee	Exhibit 4.2 to Form 10-K filed March 16, 2005
4.2	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
4.3	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
4.4	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
4.5	Third Supplemental Indenture dated as of August 17, 2016, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 6.875% Notes due 2024	Exhibit 4.1 to Form 8-K filed August 17, 2016
4.6	Fourth Supplemental Indenture dated as of August 18, 2017, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.75% Notes due 2025	Exhibit 4.1 to Form 8-K filed August 18, 2017
4.7	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
4.8	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
4.9	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
10.1	New Credit Agreement dated as of November 17, 2022 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 10-K filed February 27, 2023

10.2	Murphy Oil Corporation Annual Incentive Plan	Exhibit 10.3 to Form 10-K filed February 25, 2022
10.3	Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 29, 2012
10.4	Amendment to the Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit 10.8 to Form 10-K filed February 27, 2020
10.5	Form of employee stock option (2012 Long-Term Incentive Plan)	Exhibit 99.1 to Form 10-K filed February 28, 2014
10.6	Form of stock appreciation right (2012 Long-Term Incentive Plan)	Exhibit 99.3 to Form 10-Q filed May 7, 2014
10.7	Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit B to definitive proxy statement filed March 23, 2018
10.8	Amendment to the Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit 10.15 to Form 10-K filed February 27, 2020
10.9	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.14 to Form 10-K filed February 27, 2019
10.10	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.17 to Form 10-K filed February 27, 2020
10.11	Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.15 to Form 10-K filed February 27, 2019
10.12	Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2018 Long-Term Incentive Plan)	Exhibit 10.16 to Form 10-K filed February 27, 2019
10.13	Murphy Oil Corporation 2020 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 30, 2020
10.14	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
10.15	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
10.16	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
10.17	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
10.18	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
10.19	Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 23, 2018
10.20	First Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.1 to Form 8-K filed April 25, 2018
10.21	Second Amendment to the 2018 Stock Plan for Non-Employee Directors	Exhibit 10.24 to Form 10-K filed February 27, 2020
10.22	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
10.23	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
10.24	Murphy Oil Corporation 2021 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 26, 2021
10.25	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
10.26	Murphy Oil Corporation Non-Qualified Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.6 to Form 10-K filed February 26, 2016

PART IV

10.27	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
10.28	First Amendment to the New Credit Agreement dated as of December 16, 2022 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 10.28 to Form 10-K filed February 27, 2023
*10.29	Murphy Oil Corporation Compensation Recoupment Policy	
*10.30	Form of employee performance-based restricted stock unit (2020 LTI Plan)	
*10.31	Form of employee time-based restricted stock unit – A (2020 LTI Plan)	
*10.32	Form of employee time-based restricted stock unit – B (2020 LTI Plan)	
*10.33	Form of employee time-based restricted stock unit – C (2020 LTI Plan)	
*10.34	Form of employee time-based restricted stock unit – D (2020 LTI Plan)	
*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 Gaffney, Cline & Associates Pte. 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	
*99.1	Ryder Scott reserves audit report for U.S. Onshore and Gulf of Mexico	
*99.2	Ryder Scott reserves audit report for MP GOM JV	
*99.3	McDaniel independent audit report for Canada Onshore proved crude oil and natural gas reserves	
*99.4	Gaffney, Cline independent audit report for Vietnam proved crude oil and natural gas reserves	
101.INS	Inline XBRL Instance 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)	

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/ ROGER W. JENKINS Roger W. Jenkins, Chief Executive Officer	Date:	February 23, 2024

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 23, 2024 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/ JAMES V. KELLEY James V. Kelley, Director
/s/ ROGER W. JENKINS Roger W. Jenkins, Chief Executive Officer and Director (Principal Executive Officer)	/s/ R. MADISON MURPHY R. Madison Murphy, Director
/s/ LAWRENCE R. DICKERSON Lawrence R. Dickerson, Director	/s/ JEFFREY W. NOLAN Jeffrey W. Nolan, Director
/s/ MICHELLE A. EARLEY Michelle A. Earley, Director	/s/ ROBERT N. RYAN, JR. Robert N. Ryan, Jr., Director
/s/ ELISABETH W. KELLER Elisabeth W. Keller, Director	/s/ LAURA A. SUGG Laura A. Sugg, Director
/s/ THOMAS J. MIRELES Thomas J. Mireles, Executive Vice President and Chief Financial Officer (Principal Financial Officer)	/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 62.

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, 2023.

KPMG LLP has performed an audit of the Company's internal control over financial reporting, and their opinion thereon can be found on page 64.

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, 2023 and 2022, 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, 2023, and the related notes and financial statement schedule II (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, 2023 and 2022, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2024 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, 2023, the Company recorded depreciation, depletion, and amortization expense of $861.6 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 and comparing the development projects with the available development plans. We assessed the oil and gas prices utilized by the internal petroleum reserve engineers by comparing them to publicly available prices and recalculated the relevant market differentials. 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 23, 2024

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, 2023, 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, 2023, 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, 2023 and 2022, 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, 2023, and the related notes and financial statement schedule II (collectively, the consolidated financial statements), and our report dated February 23, 2024 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 23, 2024

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars except share amounts)		2023	2022
ASSETS			
Current assets			
Cash and cash equivalents		**$ 317,074**	$ 491,963
Accounts receivable, net		**343,992**	391,152
Inventories	Note E	**54,454**	54,513
Prepaid expenses		**36,674**	34,697
Total current assets		**752,194**	972,325
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $13,135,385 in 2023 and $12,489,970 in 2022	Note D	**8,225,197**	8,228,016
Operating lease assets	Note T	**745,185**	946,406
Deferred income taxes	Note H	**435**	117,889
Deferred charges and other assets		**43,686**	44,316
Total assets		**$ 9,766,697**	$ 10,308,952
LIABILITIES AND EQUITY			
Current liabilities			
Current maturities of long-term debt, finance lease		**$ 723**	$ 687
Accounts payable		**446,891**	543,786
Income taxes payable		**21,007**	26,544
Other taxes payable		**29,339**	22,819
Operating lease liabilities		**207,840**	220,413
Other accrued liabilities		**140,745**	443,585
Total current liabilities		**846,545**	1,257,834
Long-term debt, including finance lease obligation	Note F	**1,328,352**	1,822,452
Asset retirement obligations	Note G	**904,051**	817,268
Deferred credits and other liabilities		**309,605**	304,948
Non-current operating lease liabilities	Note T	**551,845**	742,654
Deferred income taxes	Note H	**276,646**	214,903
Total liabilities		**$ 4,217,044**	$ 5,160,059
Equity			
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued		**$ –**	$ –
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,100,628 shares in 2023 and 195,100,628 shares in 2022		**195,101**	195,101
Capital in excess of par value		**880,297**	893,578
Retained earnings		**6,546,079**	6,055,498
Accumulated other comprehensive loss	Note N	**(521,117)**	(534,686)
Treasury stock		**(1,737,566)**	(1,614,717)
Murphy Shareholders' Equity		**5,362,794**	4,994,774
Noncontrolling interest		**186,859**	154,119
Total equity		**5,549,653**	5,148,893
Total liabilities and equity		**$ 9,766,697**	$ 10,308,952

See Notes to Consolidated Financial Statements, page 70.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)	**2023**	2022	2021
Revenues and other income			
Revenue from production	**$ 3,376,639**	$ 4,038,451	$ 2,801,215
Sales of purchased natural gas	**72,215**	181,689	–
Total revenue from sales to customers	**3,448,854**	4,220,140	2,801,215
(Loss) on derivative instruments	**–**	(320,410)	(525,850)
Gain on sale of assets and other income	**11,293**	32,932	23,916
Total revenues and other income	**3,460,147**	3,932,662	2,299,281
Costs and expenses			
Lease operating expenses	**784,391**	679,342	539,546
Severance and ad valorem taxes	**42,787**	57,012	41,212
Transportation, gathering and processing	**232,985**	212,711	187,028
Costs of purchased natural gas	**51,682**	171,991	–
Exploration expenses, including undeveloped lease amortization	**234,776**	133,197	69,044
Selling and general expenses	**117,306**	131,121	121,950
Depreciation, depletion and amortization	**861,602**	776,817	795,105
Accretion of asset retirement obligations	**46,059**	46,243	46,613
Impairment of assets	**–**	–	196,296
Other operating expense	**46,530**	137,518	21,052
Total costs and expenses	**2,418,118**	2,345,952	2,017,846
Operating income from continuing operations	**1,042,029**	1,586,710	281,435
Other income (loss)			
Other (loss) income	**(8,587)**	14,310	(16,771)
Interest expense, net	**(112,373)**	(150,759)	(221,773)
Total other loss	**(120,960)**	(136,449)	(238,544)
Income from continuing operations before income taxes	**921,069**	1,450,261	42,891
Income tax expense	**195,921**	309,464	(5,862)
Income from continuing operations	**725,148**	1,140,797	48,753
Loss from discontinued operations, net of income taxes	**(1,467)**	(2,078)	(1,225)
Net income including noncontrolling interest	**723,681**	1,138,719	47,528
Less: Net income attributable to noncontrolling interest	**62,122**	173,672	121,192
NET INCOME (LOSS) ATTRIBUTABLE TO MURPHY	**$ 661,559**	$ 965,047	$ (73,664)
INCOME (LOSS) PER COMMON SHARE – BASIC			
Continuing operations	**$ 4.27**	$ 6.23	$ (0.47)
Discontinued operations	**(0.01)**	(0.01)	(0.01)
Net income (loss)	**$ 4.26**	$ 6.22	$ (0.48)
INCOME (LOSS) PER COMMON SHARE – DILUTED			
Continuing operations	**$ 4.23**	$ 6.14	$ (0.47)
Discontinued operations	**(0.01)**	(0.01)	(0.01)
Net income (loss)	**$ 4.22**	$ 6.13	$ (0.48)
Cash dividends per common share	**$ 1.100**	$ 0.825	$ 0.500
Average common shares outstanding (thousands)			
Basic	**155,234**	155,277	154,291
Diluted	**156,646**	157,475	154,291

See Notes to Consolidated Financial Statements, page 70.

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

Years Ended December 31 (Thousands of dollars)	2023	2022	2021
Net income including noncontrolling interest	$ 723,681	$ 1,138,719	$ 47,528
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	36,598	(106,335)	12,116
Retirement and postretirement benefit plans	(23,029)	99,360	59,816
Deferred loss on interest rate hedges reclassified to interest expense	–	–	1,690
Other comprehensive income (loss)	13,569	(6,975)	73,622
Comprehensive income including noncontrolling interest	737,250	1,131,744	121,150
Less: Comprehensive income attributable to noncontrolling interest	62,122	173,672	121,192
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO MURPHY	$ 675,128	$ 958,072	$ (42)

See Notes to Consolidated Financial Statements, page 70.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2023	2022	2021
Operating Activities			
Net income including noncontrolling interest	$ 723,681	$ 1,138,719	$ 47,528
Adjustments to reconcile net income to net cash provided by continuing operations activities			
Depreciation, depletion and amortization	861,602	776,817	795,105
Deferred income tax expense (benefit)	179,823	286,079	(4,146)
Unsuccessful exploration well costs and previously suspended exploration costs	169,795	82,085	17,339
Contingent consideration payment	(139,574)	–	–
Long-term non-cash compensation	61,953	89,246	63,382
Accretion of asset retirement obligations	46,059	46,243	46,613
Amortization of undeveloped leases	10,925	13,300	18,925
Mark to market loss on contingent consideration	7,113	78,285	63,147
Mark to market (gain) loss on derivative instruments	–	(214,788)	112,113
Loss from discontinued operations	1,467	2,078	1,225
Gain from sale of assets	(12)	(17,899)	–
Impairment of assets	–	–	196,296
Other operating activities, net	(74,716)	(34,193)	(53,821)
Net (increase) decrease in noncash working capital	(99,361)	(65,728)	118,457
Net cash provided by continuing operations activities	1,748,755	2,180,244	1,422,163
Investing Activities			
Property additions and dry hole costs [1]	(1,066,015)	(985,461)	(650,235)
Acquisition of oil and natural gas properties [1]	(35,578)	(128,538)	(20,244)
Proceeds from sales of property, plant and equipment	102,913	4,528	270,503
Property additions for King's Quay FPS	–	–	(17,734)
Net cash required by investing activities	(998,680)	(1,109,471)	(417,710)
Financing Activities			
Borrowings on revolving credit facility	600,000	400,000	165,000
Repayment of revolving credit facility	(600,000)	(400,000)	(365,000)
Retirement of debt	(498,175)	(647,707)	(876,358)
Early redemption of debt cost	–	(8,295)	(39,335)
Repurchase of common stock	(150,022)	–	–
Contingent consideration paid	(60,243)	(81,742)	–
Cash dividends paid	(170,978)	(128,219)	(77,204)
Distributions to noncontrolling interest	(29,382)	(183,038)	(137,517)
Withholding tax on stock-based incentive awards	(14,276)	(17,631)	(5,209)
Finance lease obligation payments	(622)	(636)	(803)
Debt issuance, net of cost	–	–	541,913
Issue costs of debt facility	(20)	(14,353)	–
Net cash required by financing activities	(923,718)	(1,081,621)	(794,513)
Net cash required by discontinued operations	–	(14,500)	–
Effect of exchange rate changes on cash and cash equivalents	(1,246)	(3,873)	638
Net (decrease) increase in cash and cash equivalents	(174,889)	(29,221)	210,578
Cash and cash equivalents at beginning of period	491,963	521,184	310,606
Cash and cash equivalents at end of period	$ 317,074	$ 491,963	$ 521,184

[1] Certain prior-period amounts have been reclassified to conform to the current period presentation.

See Notes to Consolidated Financial Statements, page 70.

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

Years Ended December 31 (Thousands of dollars except number of shares)	2023	2022	2021
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	$ –	$ –
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2023, 2022 and 2021, issued 195,100,628 shares at December 31, 2023, 2022 and 2021			
Balance at beginning and end of year	195,101	195,101	195,101
Capital in Excess of Par Value			
Balance at beginning of year	893,578	926,698	941,692
Share-based compensation	29,386	25,242	25,429
Restricted stock transactions and other [1]	(42,667)	(58,362)	(40,423)
Balance at end of year	880,297	893,578	926,698
Retained Earnings			
Balance at beginning of year	6,055,498	5,218,670	5,369,538
Net income (loss) for the year attributable to Murphy	661,559	965,047	(73,664)
Cash dividends paid	(170,978)	(128,219)	(77,204)
Balance at end of year	6,546,079	6,055,498	5,218,670
Accumulated Other Comprehensive Loss			
Balance at beginning of year	(534,686)	(527,711)	(601,333)
Foreign currency translation (losses) gains, net of income taxes	36,598	(106,335)	12,116
Retirement and postretirement benefit plans, net of income taxes	(23,029)	99,360	59,816
Deferred loss on interest rate hedge reclassified to interest expense, net of income taxes	–	–	1,690
Balance at end of year	(521,117)	(534,686)	(527,711)
Treasury Stock			
Balance at beginning of year	(1,614,717)	(1,655,447)	(1,690,661)
Purchase of treasury shares	(151,241)	–	–
Awarded restricted stock, net of forfeitures	28,392	40,730	35,214
Balance at end of year – 42,351,986 shares of common stock in 2023, 39,633,309 shares of common stock in 2022 and 40,637,578 shares of common stock in 2021	(1,737,566)	(1,614,717)	(1,655,447)
Murphy Shareholders' Equity	5,362,794	4,994,774	4,157,311
Noncontrolling Interest			
Balance at beginning of year	154,119	163,485	179,810
Net income attributable to noncontrolling interest	62,122	173,672	121,192
Distributions to noncontrolling interest owners	(29,382)	(183,038)	(137,517)
Balance at end of year	186,859	154,119	163,485
Total Equity	$ 5,549,653	$ 5,148,893	$ 4,320,796

[1] Prior-period amounts have been aggregated to conform to the current period presentation.

See Notes to Consolidated Financial Statements, page 70.

These notes are an integral part of the consolidated financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 70-102 of the Form 10-K report.

Note A – Significant Accounting Polices

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

BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of the Company and are presented in conformity with GAAP.

The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. 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. Beginning in the fourth quarter of 2018, 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 crude oil, natural gas liquids 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, 2023 and 2022, 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, 2023 and 2022, 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

Note A – Significant Accounting Policies (Continued)

charged against the allowance for doubtful accounts. The Company has not experienced any significant credit-related losses in the past three years.

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 includes 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. Interest is capitalized on significant development projects that are expected to take one year or more to complete.

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 recognized when there are indications 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 fair value. There were no impairments recognized in 2023 and 2022.

The Company records a liability for asset retirement obligations (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 and site restoration 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 criteria laid out by ASC 842, “Leases”. If a lease is present, further criteria is assessed to determine if the lease should be classified as an

Note A – Significant Accounting Policies (Continued)

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 (related to Brunei) 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” 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 Statement 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, or 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 based on 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 Consolidated Statements of Stockholders’ Equity.

Note A – Significant Accounting Policies (Continued)

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – The fair value of a derivative instrument is recognized as an asset or liability in the Company’s 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 decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. Sale and purchase contracts in the normal course of business are not designated as hedges for accounting purposes. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for the use of the hedging instrument to manage the risk. 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) that are equity settled, and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock units 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.

Note A – Significant Accounting Policies (Continued)

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 Statement 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 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.

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

None affecting the Company.

Recent Accounting Pronouncements

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 standard becomes effective for annual periods beginning after December 15, 2024. 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. Murphy is currently evaluating the impact of adopting this standard.

Reportable Segment Disclosures. In November 2023 the FASB issued ASU *2023-07 Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*. The standard becomes effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. The standard requires additional disclosures about operating segments, including segment expense information provided to the chief operating decision maker, and extends certain disclosure requirements to interim periods. The standard does not affect our determination of significant segments. Murphy is currently evaluating the impact of adopting this standard.

Note C – Revenue from Contracts with Customers

Nature of Goods and Services

The Company explores for and produces crude oil, natural gas and natural gas liquids (collectively oil and natural gas) in select basins around the globe. 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 and condensate, natural gas liquids and natural gas.

For operated oil and natural gas production where the 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 United States, the Company primarily produces oil and natural gas from fields in the Eagle Ford Shale area of South Texas and in the Gulf of Mexico. 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.

Note C – Revenue from Contracts with Customers (Continued)

Disaggregation of Revenue

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

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

		Years Ended December 31,		
(Thousands of dollars)		**2023**	2022	2021
Net crude oil and condensate revenue				
United States	Onshore	**$ 676,139**	$ 856,219	$ 626,136
	Offshore [1]	**2,072,353**	2,229,658	1,478,993
Canada	Onshore	**78,088**	131,400	119,799
	Offshore	**78,650**	117,747	92,741
Other		**11,022**	22,824	4,924
Total crude oil and condensate revenue		**2,916,252**	3,357,848	2,322,593
Net natural gas liquids revenue				
United States	Onshore	**33,178**	64,015	50,189
	Offshore [1]	**47,434**	60,424	44,411
Canada	Onshore	**8,914**	18,338	16,375
Total natural gas liquids revenue		**89,526**	142,777	110,975
Net natural gas revenue				
United States	Onshore	**21,346**	64,037	39,803
	Offshore [1]	**71,332**	161,160	81,944
Canada	Onshore	**278,183**	312,629	245,900
Total natural gas revenue		**370,861**	537,826	367,647
Revenue from production		**3,376,639**	4,038,451	2,801,215
Sales of purchased natural gas				
United States	Offshore	**–**	204	–
Canada	Onshore	**72,215**	181,485	–
Total sales of purchased natural gas		**72,215**	181,689	–
Total revenue from sales to customers		**3,448,854**	4,220,140	2,801,215
(Loss) gain on crude contracts		**–**	(320,410)	(525,850)
Gain on sale of assets and other income		**11,293**	32,932	23,916
Total revenue and other income		**$ 3,460,147**	$ 3,932,662	$ 2,299,281

[1] Includes revenue attributable to noncontrolling interest in MP GOM.

In 2022, the Company included additional line items on the face of the Consolidated Statements of Operations to report "Sales of purchased natural gas" and "Costs of purchased natural gas". 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.

Note C – Revenue from Contracts with Customers (Continued)

Contract Balances and Asset Recognition

As of December 31, 2023 and 2022, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet from continuing operations, were $193.7 million and $201.1 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, 2023, 2022 or 2021.

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.

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, 2023, 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:

Long-Term Contracts Outstanding at December 31, 2023

Location	Commodity	End Date	Description	Approximate Volumes
U.S.	Natural Gas and NGL	Q1 2030	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada	Natural Gas	Q4 2025	Contracts to sell natural gas at USD index pricing	25 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at USD index pricing	31 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at CAD fixed pricing	124 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at USD fixed pricing	25 MMCFD
Canada	Natural Gas	Q4 2024	Contracts to sell natural gas at CAD index pricing	28 MMCFD
Canada	Natural Gas	Q4 2026	Contracts to sell natural gas at USD index pricing	49 MMCFD
Canada	Natural Gas	Q4 2027	Contracts to sell natural gas at USD index pricing	30 MMCFD
Canada	Natural Gas	Q4 2028	Contracts to sell natural gas at USD index pricing	10 MMCFD

Fixed price contracts 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, 2023				December 31, 2022			
(Thousands of dollars)	Cost		Net		Cost		Net	
Exploration and production [1]	$	21,228,490	$	8,201,475 [2]	$	20,567,489	$	8,204,463 [2]
Corporate and other		132,092		23,722		150,498		23,553
Property, plant and equipment	$	21,360,582	$	8,225,197	$	20,717,987	$	8,228,016
[1] Includes unproved mineral rights as follows:	$	351,000	$	228,329	$	476,981	$	344,507

[2] Includes $15,356 in 2023 and $18,319 in 2022 related to administrative assets and support equipment.

Divestments

On September 15, 2023, the Company completed the previously announced divestment of certain non-core operated Kaybob Duvernay assets and all of our non-operated Placid Montney assets, located in Alberta, Canada for net cash proceeds of C$139.0 million. No gain or loss was recorded related to this transaction, and the effective date of the transaction was March 1, 2023.

During the third quarter of 2022, the Company completed the disposition of its 62.5% operated working interest of the Thunder Hawk field for a purchase price of $20.0 million less closing adjustments of $23.1 million, resulting in a total net payment to the buyer of $3.1 million. Additionally, the buyer assumed the asset retirement obligations of approximately $47.9 million. A $17.9 million gain on sale was recorded in the period related to the sale. In September 2022, the Company completed the disposition of the Block CA-2 asset in Brunei for contingent consideration valued at approximately $8.7 million. No gain or loss was recorded related to this sale.

Acquisitions

In August 2022, the Company acquired an additional working interest of 3.37% in the Lucius field for a purchase price of $78.5 million, net of closing adjustments.

In June 2022, the Company acquired an additional working interest of 11.0% in the Kodiak field for a purchase price of $50.0 million, net of closing adjustments.

Impairments

The following table reflects the recognized before tax impairments for each of the three years presented.

(Thousands of dollars)	2023		2022		2021	
Canada	$	–	$	–	$	171,296
Other Foreign		–		–		18,000
Corporate		–		–		7,000
	$	–	$	–	$	196,296

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, 2023, 2022 and 2021, the Company had total capitalized drilling costs pending the determination of proved reserves of $49.1 million, $171.9 million and $179.5 million, respectively. The following table reflects the net changes in capitalized exploratory well costs for each of the three years presented.

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

Note D – Property, Plant and Equipment (Continued)

(Thousands of dollars)	**2023**	2022	2021
Beginning balance at January 1	**$ 171,860**	$ 179,481	$ 181,616
Additions pending the determination of proved reserves	**48**	33,440	16,725
Reclassifications to proved properties based on the determination of proved reserves	**(82,185)**	–	–
Divestment	**–**	(7,915)	–
Capitalized exploration well costs charged to expense	**(40,605)**	(33,146)	(18,860)
Ending balance at December 31	**$ 49,118**	$ 171,860	$ 179,481

Reclassifications to proved properties of $82.2 million, for the year ended December 31, 2023, are primarily related to LDV-4X in Vietnam. Capitalized well costs charged to dry hole expense of $40.6 million are related to the Cholula-1EXP well in offshore Mexico, and Oso #1 (Atwater Valley 138), and Chinook #7 (Walker Ridge 425) exploration wells in the Gulf of Mexico. The preceding table excludes well costs of $129.2 million incurred and expensed directly to dry hole during the year ended December 31, 2023, related to the Chinook #7 (Walker Ridge 425) and Oso #1 (Atwater Valley 138) explorations well in the Gulf of Mexico.

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well and the number of projects for which exploratory well costs have been capitalized. The projects are aged based on the last well drilled in the project.

	2023			2022			2021		
(Thousands of dollars)	**Amount**	**No. of Wells**	**No. of Projects**	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs									
Zero to one year	**$ –**	**–**	**–**	$ 15,527	2	2	$ 13,273	3	3
One to two years	**–**	**–**	**–**	13,307	2	2	–	–	–
Two to three years	**2,698**	**1**	**1**	–	–	–	53,070	5	5
Three years or more	**46,420**	**3**	**3**	143,026	5	4	113,138	6	–
	$ 49,118	**4**	**4**	$ 171,860	9	8	$ 179,481	14	8

Of the $49.1 million of exploratory well costs capitalized more than one year at December 31, 2023, $26.5 million is in the U.S., $15.1 million is in Vietnam, $4.8 million is in Canada and $2.7 million is 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.

Note E – Inventories

Inventories consisted of the following for the respective periods presented:

	December 31,	
(*Thousands of dollars*)	**2023**	2022
Unsold crude oil	**$ 10,304**	$ 6,546
Materials and supplies	**44,150**	47,967
Inventories	**$ 54,454**	$ 54,513

Note F – Financing Arrangements and Debt

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

(Thousands of dollars)	December 31, 2023	2022
Notes payable		
5.75% notes, due August 2025	$ –	$ 248,675
5.875% notes, due December 2027	**443,249**	543,249
6.375% notes, due July 2028	**372,226**	451,934
7.05% notes, due May 2029	**179,708**	250,000
5.875% notes, due December 2042 [1]	**339,761**	339,761
Total notes payable	**1,334,944**	1,833,619
Unamortized debt issuance cost and discount on notes payable	**(10,107)**	(15,324)
Total notes payable, net of unamortized discount	**1,324,837**	1,818,295
Capitalized lease obligation, due through March 2029	**4,238**	4,844
Total debt including current maturities	**1,329,075**	1,823,139
Current maturities	**(723)**	(687)
Total long-term debt	**$ 1,328,352**	$ 1,822,452

[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 debt repayable over each of the next five years and thereafter are as follows: nil in 2024, nil in 2025, nil in 2026, $443.2 million in 2027, $372.2 million in 2028 and $519.5 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, 2024.

In November 2022, the Company entered into a $800 million revolving credit facility, and the previous revolving credit facility has been terminated effective November 2022. The RCF is a senior unsecured guaranteed facility which expires on November 17, 2027. On the date the Company achieves certain credit ratings (Investment Grade Ratings Date), certain covenants will be modified as set forth in the RCF. In addition, prior to Investment Grade Ratings Date, the Company will be required to comply with a maximum consolidated leverage ratio of 3.50x 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 bear 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 is the highest of (a) the Prime Rate in effect on such day, (b) the New York Federal Reserve Bank (NYFRB) 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 is equal to (a) the Term SOFR Rate for such Interest Period, plus (b) 0.10%. The "Adjusted Daily Simple SOFR Rate" of interest is equal to (a) the Daily Simple SOFR, plus (b) 0.10%. The "Applicable Rate" of interest means, for any day, the applicable rate per annum based upon the ratings of Moody's and S&P, respectively. The Company incurred $14.4 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 RCF. At December 31, 2023, the Company had no outstanding borrowings under the RCF and $3.8 million of outstanding letters of credit, which reduces the borrowing capacity of the RCF. At December 31, 2023, the interest rate in effect on borrowings under the facility would have been 7.70%. At December 31, 2023, the Company was in compliance with all covenants related to the RCF.

In November 2023, the Company tendered a total of $249.5 million of its 2027 Notes, 2028 Notes and 2029 Notes, retiring $250 million in aggregate principal. The cost of debt extinguishment of $1.3 million is included in "Interest expense, net" on the Consolidated Statement of Operations for the year ended December 31, 2023.

Note F - Financing Arrangements and Debt (Continued)

There were no additional cash costs related to the November 2023 debt extinguishment on the 2027 Notes, 2028 Notes and 2029 Notes for the year ended December 31, 2023.

In September 2023, the Company redeemed the remaining $248.7 million principal outstanding of its 2025 Notes. The non-cash costs of debt extinguishment of $0.9 million is included in “Interest expense, net” on the Consolidated Statement of Operations for the year ended December 31, 2023.

In November 2022, the Company redeemed $200.0 million aggregate principal amount of its 2025 Notes. The cost of debt extinguishment of $3.9 is included in “Interest expense, net” on the Consolidated Statement of Operations for the year ended December 31, 2022. The cash costs of $2.9 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2022.

In September and October 2022, the Company paid a total of $7.2 million to complete the open market repurchases of $9.2 million aggregate principal amount of its 6.125% senior notes due 2042 (2042 Notes). There were no additional cash costs related to the September and October 2022 debt extinguishment on the 2042 Notes for the year ended December 31, 2022.

In August 2022, the Company redeemed the remaining $42.4 million of its 6.875% senior notes due in 2024 (2024 Notes) and tendered $100.0 million and $98.1 million aggregate principal amount of its 2025 Notes and 2028 Notes, respectively. The total cost of the debt extinguishment of $4.0 million is included in “Interest expense, net” on the Consolidated Statement of Operations for the year ended December 31, 2022. The debt extinguishment on the 2025 and 2028 Notes had cash costs of $2.0 million and is shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2022.

In June 2022, the Company redeemed $200.0 million aggregate principal amount of its 6.875% 2024 Notes. The cost of the debt extinguishment of $4.3 million is included in “Interest expense, net” on the Consolidated Statement of Operations for the year ended December 31, 2022. The cash costs of $3.4 million are shown as a financing activity on the Consolidated Statement of Cash Flows for the year ended December 31, 2022.

Note G – Asset Retirement Obligations

The asset retirement obligations 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.

(Thousands of dollars)	**2023**	2022
Balance at beginning of year	**$ 911,653**	$ 971,893
Accretion	**46,059**	46,243
Liabilities incurred	**20,628**	46,449
Revisions of previous estimates	**29,056**	(78,229)
Liabilities settled	**(95,637)**	(64,255)
Changes due to translation of foreign currencies	**3,004**	(10,448)
Balance at end of year	**914,763**	911,653
Current portion of liability [1]	**(10,712)**	(94,385)
Noncurrent portion of liability	**$ 904,051**	$ 817,268

[1] Included in “Other accrued liabilities” on the Consolidated Balance Sheets.

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)	**2023**	2022	2021
Income (loss) from continuing operations before income taxes			
United States	**$ 901,761**	$ 1,306,200	$ 114,659
Foreign	**19,308**	144,061	(71,768)
Total	**$ 921,069**	$ 1,450,261	$ 42,891
Income tax expense (benefit)			
U.S. Federal – Current	**$ –**	$ –	$ –
– Deferred	**170,115**	234,749	(1,480)
Total U.S. Federal	**170,115**	234,749	(1,480)
State	**6,622**	9,010	3,303
Foreign – Current	**13,182**	18,134	(5,158)
– Deferred	**6,002**	47,571	(2,527)
Total Foreign	**19,184**	65,705	(7,685)
Total	**$ 195,921**	$ 309,464	$ (5,862)

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)	**2023**	2022	2021
Income tax expense (benefit) based on the U.S. statutory tax rate	**$ 193,424**	$ 304,555	$ 9,007
Foreign income (loss) subject to foreign tax rates different than the U.S. statutory rate	**7,597**	10,823	13,270
State income taxes, net of federal benefit	**4,725**	7,118	2,500
U.S. tax benefit on certain foreign upstream investments	**–**	–	(8,916)
Change in deferred tax asset valuation allowance related to other foreign exploration expenditures	**10,853**	24,748	4,814
Tax effect on income attributable to noncontrolling interest	**(13,046)**	(36,471)	(25,450)
Other, net	**(7,632)**	(1,309)	(1,087)
Total	**$ 195,921**	$ 309,464	$ (5,862)

Note H – Income Taxes (Continued)

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)	**2023**	2022
Deferred tax assets		
Property and leasehold costs	**$ 240,065**	$ 242,467
Liabilities for dismantlements	**34,258**	31,017
Postretirement and other employee benefits	**82,437**	86,798
U. S. net operating loss	**357,490**	442,699
Investment in partnership	**14,655**	11,595
Other deferred tax assets	**48,778**	111,212
Total gross deferred tax assets	**777,683**	925,788
Less valuation allowance	**(146,861)**	(136,008)
Net deferred tax assets	**630,822**	789,780
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	**(5,000)**	(5,000)
Accumulated depreciation, depletion and amortization	**(847,981)**	(796,510)
Other deferred tax liabilities	**(54,052)**	(85,284)
Total gross deferred tax liabilities	**(907,033)**	(886,794)
Net deferred tax (liabilities) assets	**$ (276,211)**	$ (97,014)

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 $10.9 million in 2023, 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 $1.7 billion at year-end 2023 with a corresponding deferred tax asset of $357.5 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 2036 and 2037.

Other Information

Currently, the Company considers $100 million of Canada's past foreign earnings not permanently reinvested, with an accompanying $5 million liability. At December 31, 2023, $1.5 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.

Note H – Income Taxes (Continued)

(Thousands of dollars)	**2023**	2022	2021
Balance at January 1	**$ 3,928**	$ 2,903	$ 2,832
Additions for tax positions related to current year	**–**	77	71
Additions for tax positions related to prior year	**2,456**	948	–
Balance at December 31	**$ 6,384**	$ 3,928	$ 2,903

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, 2023, 2022 and 2021, 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 2024, 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 Statement of Operations during 2024.

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, 2023, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States – 2016; Canada – 2016; and Malaysia – 2017. 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.

The Company currently has outstanding incentive awards issued to certain employees under the Annual Incentive Plan (AIP), the 2012 Long-Term Incentive Plan (2012 Long-Term Plan), the 2018 Long-Term Incentive Plan (2018 Long-Term Plan) and the 2020 Long-Term Incentive Plan (2020 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 2020 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), SARs, restricted stock, restricted stock units (RSUs), performance units, performance shares, dividend equivalents and other stock-based incentives. The 2020 Long-Term Plan expires in 2030. A total of 5 million shares are issuable during the life of the 2020 Long-Term Plan. 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, 2.1 million shares are available for grant under the 2020 Long-Term Plan at December 31, 2023.

The Stock Plan for Non-Employee Directors (2021 NED Plan) permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors. The

Note I – Incentive Plans (Continued)

Company currently has outstanding incentive awards issued to Directors under the 2021 NED Plan and the 2018 Stock Plan for Non-Employee Directors (2018 NED Plan).

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

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)	**2023**	2022	2021
Compensation charged against income before income tax benefit	**$ 58,760**	$ 74,587	$ 43,660
Related income tax benefit recognized in income	**9,330**	12,710	7,196

As of December 31, 2023, there were $47.4 million in compensation costs, to be expensed over approximately the next three years, related to unvested share-based compensation arrangements granted by the Company. Employees receive net shares, after applicable withholding obligations, upon each stock option exercise and restricted stock unit vest.

Equity-Settled Awards

PERFORMANCE-BASED RESTRICTED STOCK UNITS – PSUs to be settled in common shares were granted in 2020 under the 2018 Long-Term Plan, and in 2021, 2022 and 2023 under the 2020 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. For PSUs, the performance conditions are based on the Company's total shareholder return (80% weighting), compared to an industry peer group of companies, and the EBITDA divided by Average Capital Employed metric (20% weighting) for PSU awards, over the performance period. 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.

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

(Number of stock units)	**2023**	2022	2021
Outstanding at beginning of year	**2,148,467**	2,670,756	2,207,429
Granted	**409,160**	595,700	1,156,800
Vested and issued	**(408,135)**	(654,177)	(642,473)
Forfeited	**(331,304)**	(463,812)	(51,000)
Outstanding at end of year	**1,818,188**	2,148,467	2,670,756

The fair value of the equity-settled performance-based awards granted in each year 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 period. The risk-free interest 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 2023, 2022 and 2021 are presented in the following table.

	2023	2022	2021
Fair value per share at grant date	**$60.46**	$37.77 - $47.37	$16.03
Assumptions			
Expected volatility	**81.00%**	79.00% - 81.00%	74.00%
Risk-free interest rate	**3.90%**	1.39% -2.85%	0.18%
Stock beta	**1.034**	1.195 - 1.200	1.169
Expected life	**3.0 years**	3.0 years	3.0 years

Note I – Incentive Plans (Continued)

TIME-BASED RESTRICTED STOCK UNITS – Time-based RSUs have been granted to the Company's Non-Employee Directors (NED) under the 2018 NED Plan and 2021 NED Plan, and to certain employees under the 2020 Long-Term Plan.

The fair value of the time-based restricted stock units awarded for each of the last three years are presented in the following table.

Type of Plan	Valuation Methodology	2023	2022	2021
Non-Employee Directors [1]	Closing Stock Price at Grant Date	**$43.27**	$32.84	$13.14 - $23.58
Long-Term Incentive Plan [2]	Average Low/High Stock Price at Grant Date	**$42.20**	$29.80 - $49.86	$12.30

[1] Under the 2021 NED Plan, RSUs granted in 2023 are scheduled to vest in February 2024.

[2] The RSUs granted under the 2018 and 2020 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)	2023	2022	2021
Outstanding at beginning of year	**1,227,792**	1,451,438	1,383,043
Granted	**556,100**	416,492	573,907
Vested and issued	**(517,047)**	(462,418)	(476,012)
Forfeited	**(47,261)**	(177,720)	(29,500)
Outstanding at end of year	**1,219,584**	1,227,792	1,451,438

STOCK OPTIONS – In 2017, the Company ceased the inclusion of stock options and SARs as a part of the long-term incentive compensation mix.

Prior to 2017, the Committee fixed the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixed the option term at no more than seven years from such date. Each option granted to date under the 2012 Long-Term Plan has been nonqualified, with a term of seven years and an option price equal to FMV at date of grant. Under these plans, one-half of each grant is generally exercisable after two years and the remainder after three years. For stock options, the number of shares issued upon exercise is reduced for settlement of applicable statutory income tax withholdings owed by the grantee.

The fair value of each option award was estimated on the date of grant using the Black-Scholes pricing model based on the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free interest rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

Note I – Incentive Plans (Continued)

Changes in stock options outstanding during the last three years are presented in the following table.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2020	2,048,400	40.14
Exercised	(170,000)	17.57
Forfeited	(558,900)	52.61
Outstanding at December 31, 2021	1,319,500	37.77
Exercised	(760,500)	23.29
Forfeited	(546,000)	49.65
Outstanding at December 31, 2022	13,000	28.51
Exercised	**(11,000)**	**28.51**
Forfeited	**(2,000)**	**28.51**
Outstanding at December 31, 2023	**–**	**–**
Exercisable at December 31, 2020	2,048,400	37.88
Exercisable at December 31, 2021	1,319,500	34.25
Exercisable at December 31, 2022	13,000	28.51
Exercisable at December 31, 2023	**–**	**–**

The total intrinsic value of options exercised during 2023 was $0.16 million. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's common stock.

Cash-Settled Awards

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

SAR awards have terms similar to stock options. 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 pre-tax expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was $29.4 million in 2023, $49.3 million in 2022 and $18.2 million in 2021.

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 $30.9 million, $42.9 million and $29.0 million was recorded in 2023, 2022 and 2021, 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. downstream 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.

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

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.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2023**	2022	**2023**	2022
Change in benefit obligation				
Obligation at January 1	**$ 663,073**	$ 939,380	**$ 67,679**	$ 96,133
Service cost	**6,542**	7,875	**495**	968
Interest cost	**34,140**	22,747	**3,241**	2,211
Participant contributions	**–**	–	**2,629**	2,283
Actuarial loss (gain)	**26,625**	(238,407)	**(5,567)**	(29,533)
Medicare Part D subsidy	**–**	–	**299**	331
Exchange rate changes	**6,089**	(21,018)	**2**	(20)
Benefits paid	**(56,296)**	(47,504)	**(4,970)**	(4,694)
Plan amendments [1]	**18,978**	–	**–**	–
Obligation at December 31	**699,151**	663,073	**63,808**	67,679
Change in plan assets				
Fair value of plan assets at January 1	**450,944**	611,302	**–**	–
Actual return on plan assets	**39,953**	(133,395)	**–**	–
Employer contributions	**37,546**	41,145	**2,042**	2,080
Participant contributions	**–**	–	**2,629**	2,283
Medicare Part D subsidy	**–**	–	**299**	331
Exchange rate changes	**5,662**	(20,604)	**–**	–
Benefits paid	**(56,296)**	(47,504)	**(4,970)**	(4,694)
Fair value of plan assets at December 31	**477,809**	450,944	**–**	–
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**3,192**	3,584	**–**	–
Other accrued liabilities	**(10,219)**	(9,693)	**(4,433)**	(4,830)
Deferred credits and other liabilities	**(214,315)**	(206,020)	**(59,375)**	(62,849)
Fund Status and net plan liability recognized at December 31	**$ (221,342)**	$ (212,129)	**$ (63,808)**	$ (67,679)

[1] At December 31, 2023, the Company recognized an increase to its domestic plan benefit obligation related to a plan amendment. The amendment provides a permanent increase to benefits for retirees and beneficiaries who commenced payments prior to 2020.

In 2023, the increase to the pension benefits obligation is primarily due to the decrease in the interest rate assumption.

At December 31, 2023, amounts included in “Accumulated other comprehensive loss” (AOCL) 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)	$ (202,868)	$ 44,165
Prior service (credit) cost	(20,561)	3,937
	$ (223,429)	$ 48,102

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)	**2023**	2022	**2023**	2022	**2023**	2022
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$ 534,751**	$ 511,375	**$ 523,096**	$ 499,338	**$ 461,363**	$ 434,283
Unfunded nonqualified and directors’ plans where accumulated benefit obligation exceeds fair value of plan assets	**151,146**	141,917	**148,661**	139,634	**–**	–
Unfunded other postretirement plans	**63,808**	67,679	**63,808**	67,679	**–**	–

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)	**2023**	2022	2021	**2023**	2022	2021
Service cost	**$ 6,542**	$ 7,875	$ 8,199	**$ 495**	$ 968	$ 1,295
Interest cost	**34,140**	22,747	14,784	**3,241**	2,211	2,071
Expected return on plan assets	**(32,839)**	(36,458)	(19,222)	**–**	–	–
Amortization of prior service cost (credit)	**620**	(684)	591	**(532)**	(532)	–
Recognized actuarial (gain) loss	**9,776**	16,098	20,565	**(3,512)**	(615)	(29)
Net periodic benefit expense	**18,239**	9,578	24,917	**(308)**	2,032	3,337
Curtailment expense	**219**	–	–	**–**	–	–
Total net periodic benefit expense	**$ 18,458**	$ 9,578	$ 24,917	**$ (308)**	$ 2,032	$ 3,337

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

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2023**	2022	**2023**	2022
Benefit obligation at December 31	**$ 133,822**	$ 122,915	**$ 115**	$ 107
Fair value of plan assets at December 31	**119,236**	115,862	**–**	–
Net plan liabilities recognized	**(14,586)**	(7,053)	**(115)**	(107)
Net periodic benefit expense (benefit)	**1,387**	(5,322)	**(44)**	62

The following table provides the weighted-average assumptions used in the measurement of the Company’s benefit obligations at December 31, 2023 and 2022 and net periodic benefit expense for 2023 and 2022.

Note J – Employee and Retiree Benefit Plans (Continued)

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31,		December 31,		Year		Year	
	2023	2022	**2023**	2022	**2023**	2022	**2023**	2022
Discount rate on obligation, interest cost and service cost	**5.03 %**	5.30 %	**5.15 %**	5.41 %	**5.27 %**	3.13 %	**5.41 %**	2.86 %
Rate of compensation increase	**3.52 %**	3.50 %	**–**	–	**3.52 %**	3.00 %	**–**	–
Cash balance interest credit rate	**3.20 %**	3.20 %	**–**	–	**–**	–	**–**	–
Expected return on plan assets	**–**	–	**–**	–	**7.35 %**	6.24 %	**–**	–

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
2024	$ 47,042	$ 4,433
2025	47,424	4,456
2026	48,004	4,479
2027	48,481	4,491
2028	49,834	4,614
2029-2033	248,023	22,037

For purposes of measuring postretirement benefit obligations at December 31, 2023, the future annual rates of increase in the cost of health care were assumed to be 7.4% for 2024 decreasing each year to an ultimate rate of 4.0% in 2048 and thereafter.

During 2023, the Company made contributions of $34.7 million to its domestic defined benefit pension plans and $2.0 million to its domestic postretirement benefits plan. During 2024, the Company currently expects to make contributions of $35.8 million to its domestic defined benefit pension plans, $2.2 million to its foreign defined benefit pension plans and $4.4 million to its domestic postretirement benefits plan.

PLAN INVESTMENTS – Murphy Oil Corporation maintains an Investment Policy Statement (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 includes 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.

Note J – Employee and Retiree Benefit Plans (Continued)

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,	
	2023	2022
Equity securities	**62.6 %**	65.7 %
Fixed income securities	**29.1 %**	23.4 %
Alternatives	**5.1 %**	7.3 %
Cash equivalents	**3.2 %**	3.6 %
	100.0 %	100.0 %

The Company’s weighted average expected return on plan assets was 7.4% in 2023 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 7.4% expected return was comprised of the weighted average expected future equity securities return of 8.4% and a fixed income securities return of 4.7%. An average expected investment expense of 0.8% is included in this calculation. Over the last 10 years, the return on funded retirement plan assets has averaged 3.0%.

At December 31, 2023, 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, 2023	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	**$ 105,212**	**$ 105,212**	**$ –**	**$ –**
U.S. small/midcap	**64,165**	**64,165**	**–**	**–**
Other alternative strategies	**3,831**	**–**	**–**	**3,831**
International equity	**31,820**	**31,820**	**–**	**–**
Emerging market equity	**10,525**	**10,525**	**–**	**–**
Fixed income securities:				
U.S. fixed income	**132,608**	**56,381**	**76,227**	**–**
Cash and equivalents	**10,412**	**10,412**	**—**	**–**
Total Domestic Plans	**358,573**	**278,515**	**76,227**	**3,831**
Foreign Plans				
Equity securities funds	**24,389**	**–**	**24,389**	**–**
Fixed income securities funds	**23,930**	**–**	**23,930**	**–**
Diversified pooled fund	**45,162**	**–**	**45,162**	**–**
Other	**20,623**	**–**	**–**	**20,623**
Cash and equivalents	**5,133**	**–**	**5,133**	**–**
Total Foreign Plans	**119,236**	**–**	**98,613**	**20,623**
Total	**$ 477,809**	**$ 278,515**	**$ 174,841**	**$ 24,454**

Note J – Employee and Retiree Benefit Plans (Continued)

At December 31, 2022, 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, 2022	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	$ 96,433	$ 96,433	$ –	$ –
U.S. small/midcap	64,421	64,421	–	–
Other alternative strategies	12,106	–	–	12,106
International equity	44,672	44,672	–	–
Emerging market equity	13,541	13,541	–	–
Fixed income securities:				
U.S. fixed income	85,190	35,661	49,528	–
Cash and equivalents	18,719	18,719	–	–
Total Domestic Plans	335,082	273,447	49,528	12,106
Foreign Plans				
Equity securities funds	23,877	–	23,877	–
Fixed income securities funds	30,727	–	30,727	–
Diversified pooled fund	31,246	–	31,246	–
Other	20,628	–	–	20,628
Cash and equivalents	9,384	–	9,384	–
Total Foreign Plans	115,862	–	95,234	20,628
Total	$ 450,944	$ 273,447	$ 144,763	$ 32,734

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 two investments. One of these investments is valued annually based on net asset value and permits withdrawals annually after a 90-day notice, and the other investment is also valued quarterly based on net asset values and has a three-year lock-up period and a 95-day notice following the lock-up period.

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, 2021	$ 82,854
Actual return on plan assets:	
Relating to assets held at the reporting date	(38,389)
Purchases, sales and settlements	(11,731)
Total at December 31, 2022	32,734
Actual return on plan assets:	
Relating to assets held at the reporting date	**711**
Relating to assets sold during the period	**(8,991)**
Total at December 31, 2023	**$ 24,454**

THRIFT PLANS – Most full-time U.S. employees of the Company may participate in thrift 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 allotment based on years of participation in the plans, with a maximum match of 6.0%. Amounts charged to expense for the Company's match to these plans were $8.5 million in 2023, $6.0 million in 2022 and $5.4 million in 2021.

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 New York Mercantile Exchange. 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.

Certain interest rate derivative contracts were previously accounted for as hedges and the gain or loss associated with recording the fair value of these contracts was deferred in AOCL and amortized to "Interest expense, net" over time. In 2021, the Company redeemed all of the remaining notes due 2022, which were associated with the interest rate derivative contracts and expensed the remainder of the previously deferred loss on the interest rate swap of $2.1 million to "Interest expense, net" in the Consolidated Statement of Operations.

Commodity Price Risks

During 2022, the Company had crude oil swaps and collar contracts. Under the swaps contracts, which matured monthly, the Company paid the average monthly price in effect and received the fixed contract price on a notional amount of sales volume, thereby fixing the price for the commodity sold. Under the collar contracts, which also matured monthly, the Company purchased a put option and sold a call option with no net premiums paid to or received from counterparties. Upon maturity, collar contracts required payments by the Company if the NYMEX average closing price was above the ceiling price or payments to the Company if the NYMEX average closing price was below the floor price.

At December 31, 2023 and December 31, 2022, the Company did not have any outstanding crude oil derivative contracts. At December 31, 2021, the Company had 20,000 barrels per day in NYMEX WTI swap contracts at a price per barrel of $44.88 and 25,000 barrels per day in NYMEX WTI collar contracts with an average ceiling price per barrel of $75.20 and an average floor price per barrel of $63.24, both maturing ratably during 2022.

Note K – Financial Instruments and Risk Management (Continued)

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, 2023 and 2022.

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.

(Thousands of dollars)		Gain (Loss) Year Ended December 31,		
Type of Derivative Contract	**Statement of Operations Locations**	**2023**	2022	2021
Commodity swaps	(Loss) on derivative instruments	**$ –**	$ (160,690)	$ (510,596)
Commodity collars	(Loss) on derivative instruments	**–**	(159,721)	(15,254)

Credit Risks

The Company's primary credit risks are 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 – Earnings Per Share

Net income (loss) 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)	**2023**	2022	2021
Basic method	**155,233,560**	155,276,533	154,290,741
Dilutive stock options and restricted stock units [1]	**1,412,869**	2,198,305	–
Diluted method	**156,646,429**	157,474,838	154,290,741

[1] Due to a net loss recognized by the Company for the year ended December 31, 2021, no unvested stock awards were included in the computation of diluted earnings per share because the effect would have been antidilutive.

The following table reflects certain options to purchase shares of common stock that were outstanding during each of the three years presented but were not included in the computation of dilutive earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2023	2022	2021
Antidilutive stock options excluded from diluted shares	**–**	126,000	1,420,992
Weighted average price of these options	**–**	$49.65	$35.30

Note M – Other Financial Information

GAIN 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 $10.8 million loss in 2023, $23.0 million gain in 2022 and $1.0 million gain in 2021.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued
Note M – Other Financial Information (Continued)

Noncash operating working capital (increased) decreased during each of the three years presented as shown in the following table.

(Thousands of dollars)	**2023**	2022	2021
Net (increase) decrease in operating working capital, excluding cash and cash equivalents:			
(Increase) decrease in accounts receivable	**$ 47,151**	$ (137,228)	$ 8,056
(Increase) decrease in inventories	**329**	(1,534)	12,809
(Increase) decrease in prepaid expenses	**(1,293)**	(3,413)	2,003
Increase (decrease) in accounts payable and accrued liabilities [1]	**(140,011)**	69,854	95,166
Increase (decrease) in income taxes payable	**(5,537)**	6,593	423
Net (increase) decrease in noncash operating working capital	**$ (99,361)**	$ (65,728)	$ 118,457
Supplementary disclosures:			
Cash income taxes paid, net of refunds	**$ 12,356**	$ 24,853	$ 2,138
Interest paid, net of amounts capitalized of $14.5 million in 2023, $16.3 million in 2022 and $16.1 million in 2021	**108,912**	149,957	165,699
Non-cash investing activities:			
Asset retirement costs capitalized	**$ 32,975**	$ (21,147)	$ 54,439
(Increase) decrease in capital expenditure accrual	**17,517**	(31,397)	9,788

[1] Excludes receivable/payable balances relating to mark-to-market of crude contracts.

Note N – Accumulated Other Comprehensive Loss

The components of AOCL 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, 2021	$ (311,895)	$ (215,816)	$ (527,711)
2022 components of other comprehensive income (loss):			
Before reclassifications to income	(106,335)	87,362	(18,973)
Reclassifications to income	–	11,998 [1]	11,998
Net other comprehensive income	(106,335)	99,360	(6,975)
Balance at December 31, 2022	(418,230)	(116,456)	(534,686)
2023 components of other comprehensive income (loss):			
Before reclassifications to income	**36,598**	**(27,580)**	**9,018**
Reclassifications to income	**–**	**4,551** [1]	**4,551**
Net other comprehensive income (loss)	**36,598**	**(23,029)**	**13,569**
Balance at December 31, 2023	**$ (381,632)**	**$ (139,485)**	**$ (521,117)**

[1] Reclassifications before taxes of $5.6 million and $15.3 million are included in the computation of net periodic benefit expense in 2023 and 2022, respectively. See Note J for additional information. Related income taxes of $1.1 million and $3.3 million are included in income tax expense in 2023 and 2022, 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, 2023				December 31, 2022			
(Thousands of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**	Level 1	Level 2	Level 3	Total
Liabilities:								
Nonqualified employee savings plan	**$ 17,785**	**$ –**	**$ –**	**$ 17,785**	$ 15,135	$ –	$ –	$ 15,135
	$ 17,785	**$ –**	**$ –**	**$ 17,785**	$ 15,135	$ –	$ –	$ 15,135

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.

In 2019, the Company acquired strategic deepwater Gulf of Mexico assets from LLOG Exploration Offshore L.L.C. and LLOG Bluewater Holdings, L.L.C., (LLOG). Under the terms of the transaction, in addition to the consideration paid, Murphy had an obligation to pay additional contingent consideration of up to $200 million in the event that certain revenue thresholds are exceeded between 2019 and 2022; and $50 million following first oil from certain development projects. The revenue threshold was not exceeded for 2019 or 2020; however, the threshold was met in 2021 and 2022.

In 2018, the Company, through a subsidiary, acquired Gulf of Mexico producing assets from Petrobras America Inc. (PAI), a subsidiary of Petróleo Brasileiro S.A. Under the terms of the transaction, in addition to the consideration paid, Murphy had an obligation to pay additional contingent consideration of up to $150 million if certain price and production thresholds are exceeded beginning in 2019 through 2025; and $50 million carry for PAI development costs in the St. Malo Field if certain enhanced oil recovery projects are undertaken. The price and production thresholds were not exceeded for 2019 and 2020; however, the thresholds were met in 2021 and 2022. As of December 31, 2021, Murphy had completely funded the carried interest.

As at December 31, 2022, the Company's liabilities with PAI and LLOG were based on realized inputs of volumes and pricing as a result of contractual thresholds and time durations being achieved. As a result, the related liability as at December 31, 2022, of $192.7 million, is no longer subject to fair value measurement. The liability is included in "Other accrued liabilities" in the Consolidated Balance Sheets and the changes in fair value of the contingent consideration during 2022 were recorded in "Other (loss) income" in the Consolidated Statements of Operations.

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, 2023 and 2022.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2023 and 2022. 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 nominal.

	December 31,			
	2023		2022	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial liabilities:				
Current and long-term debt	**$ 1,329,075**	**$ 1,265,185**	$ 1,823,139	$ 1,668,216

Fair Values – Nonrecurring

There were no impairment expenses incurred in 2023 and 2022.

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 Gulf of Mexico transportation contracts require minimum monthly payments through 2045, while the Canada Onshore processing 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 $225.9 million in 2024, $126.0 million in 2025, $114.7 million in 2026, $103.5 million in 2027 and $94.4 million in 2028. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Total costs incurred under these service arrangements were $295.1 million in 2023, $216.4 million in 2022 and $151.8 million in 2021.

Commitments for capital expenditures were approximately $209.8 million at December 31, 2023, including $173.3 million for costs to develop deepwater U.S. Gulf of Mexico fields, $13.3 million for Eagle Ford Shale, $19.2 million for Canada and $4.0 million for Other Foreign.

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; 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 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 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 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 recent 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.

There continues to be an increase in regulatory oversight of the oil and gas industry at the federal level, with a focus on climate change and GHG emissions (including methane emissions). For example, in December 2023, the U.S. EPA announced 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. In addition, there have been a number of executive orders issued that address climate change, including creation of climate-related task forces, directives to federal agencies to procure carbon-free electricity, and a goal of a carbon pollution-free power sector by 2035 and a net-zero emissions U.S. economy by 2050. Executive orders have also been issued related to oil and gas activities on federal lands, infrastructure and environmental justice. 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. The Paris Agreement entered into force in November 2016. Although the U.S. officially withdrew from the Paris Agreement on November 4, 2020, the U.S. has since rejoined the Paris Agreement, which became effective for the U.S. on February 19, 2021.

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*)	**2023**	2022	2021
Beginning of year	**155,467,319**	154,463,050	153,598,625
Stock options exercised [1]	**2,657**	181,655	32,554
Restricted stock awards [1]	**689,824**	822,614	831,871
Treasury shares purchased	**(3,411,158)**	–	–
End of year	**152,748,642**	155,467,319	154,463,050

[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.

On August 4, 2022, the Board authorized a share repurchase program of up to $300 million of the Company's common stock. During 2023, the Board authorized an increase to the program, bringing the total amount allowed to be repurchased under the program to $600 million. 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. 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.

During the year ended December 31, 2023, the Company repurchased 3,411,158 shares of its common stock under the share repurchase program for $151.2 million, including excise taxes, commissions and fees. As of December 31, 2023, the Company had $450 million remaining available to repurchase.

Note S – Business Segments

Murphy's reportable segments are organized into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada and all other countries. Each of these segments derive revenues primarily from the sale of crude oil, condensate, natural gas liquids and/or natural gas. The Company's management evaluates segment performance based on income (loss) from operations, excluding interest income and interest expense.

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.

	2023	2022	2021
Chevron Corporation	**16 %**	19 %	30 %
ExxonMobil Corporation	**27 %**	12 %	N/A

Due to the quantity of active oil and 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, 2023 and 2022. The former U.K. and U.S. downstream units have been reported as discontinued operations for all periods presented in these consolidated financial statements.

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 and other activities, including interest income, other gains and losses (including foreign exchange gains/losses and realized/unrealized gains/losses on crude oil contracts), interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals.

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

Note S – Business Segments (Continued)

	Exploration and Production						
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2023							
Segment income (loss) - including NCI [1]	**$ 905.1**	**$ 41.6**	**$ (65.5)**	**$ 881.2**	**$ (156.0)**	**$ (1.5)**	**$ 723.7**
Revenues from external customers	**2,928.3**	**517.5**	**11.0**	**3,456.8**	**3.4**	**—**	**3,460.2**
Interest and other income (loss)	**(3.9)**	**(1.1)**	**(0.6)**	**(5.6)**	**(3.0)**	**–**	**(8.6)**
Interest expense, net of capitalization	**(0.1)**	**(0.2)**	**(0.2)**	**(0.5)**	**(111.9)**	**–**	**(112.4)**
Income tax expense (benefit)	**232.7**	**11.2**	**(6.1)**	**237.8**	**(41.8)**	**–**	**196.0**
Significant noncash charges (credits)							
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**
Amortization of undeveloped leases	**8.1**	**0.1**	**2.7**	**10.9**	**–**	**–**	**10.9**
Deferred and noncurrent income taxes	**229.6**	**7.5**	**(6.7)**	**230.4**	**(50.6)**	**–**	**179.8**
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**	**365.5**	**0.8**	**9,766.6**
Year ended December 31, 2022							
Segment income (loss) - including NCI [1]	$ 1,521.9	134.2	(77.0)	1,579.1	$ (438.3)	(2.1)	1,138.7
Revenues from external customers	3,461.2	762.9	23.0	4,247.1	(314.4)	–	3,932.7
Interest and other income (loss)	(6.6)	(1.9)	(0.5)	(9.0)	23.3	–	14.3
Interest expense, net of capitalization	(0.1)	–	(0.3)	(0.4)	(150.4)	–	(150.8)
Income tax expense (benefit)	370.8	43.6	2.9	417.3	(107.8)	–	309.5
Significant noncash charges (credits)							
Depreciation, depletion and amortization	617.0	141.5	5.4	763.9	12.9	–	776.8
Accretion of asset retirement obligations	36.5	9.6	0.1	46.2	–	–	46.2
Amortization of undeveloped leases	8.7	0.2	4.4	13.3	–	–	13.3
Deferred and noncurrent income taxes	362.7	34.8	0.6	398.1	(112.0)	–	286.1
Additions to property, plant, equipment	838.6	208.5	(5.7)	1,041.4	21.9	–	1,063.3
Total assets at year-end	6,930.6	2,125.6	217.4	9,273.6	1,034.6	0.8	10,309.0
Year ended December 31, 2021							
Segment income (loss) - including NCI [1]	$ 766.3	$ (16.1)	$ (33.5)	$ 716.7	$ (668.0)	$ (1.2)	$ 47.5
Revenues from external customers	2,337.5	476.3	4.9	2,818.7	(519.4)	–	2,299.3
Interest and other income (loss)	(11.6)	(1.9)	3.2	(10.3)	(6.5)	–	(16.8)
Interest expense, net of capitalization	–	–	(0.2)	(0.2)	(221.6)	–	(221.8)

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

Note S – Business Segments (Continued)

	Exploration and Production						
(Millions of dollars)	United States [1]	Canada	Other	Total E&P	Corporate and Other	Discontinued Operations	Consolidated Total
Income tax expense (benefit)	183.9	(1.7)	(9.5)	172.7	(178.6)	–	(5.9)
Significant noncash charges (credits)							
Impairment of assets	–	171.3	18.0	189.3	7.0	–	196.3
Depreciation, depletion and amortization	616.5	163.8	1.8	782.1	13.0	–	795.1
Accretion of asset retirement obligations	36.9	9.7	–	46.6	–	–	46.6
Amortization of undeveloped leases	11.1	0.2	7.6	18.9	–	–	18.9
Deferred and noncurrent income taxes	176.3	(1.9)	(8.0)	166.4	(170.5)	–	(4.1)
Additions to property, plant, equipment	519.5	52.7	13.1	585.3	–	–	585.3
Total assets at year-end	6,591.6	2,231.9	259.8	9,083.3	1,220.8	0.8	10,304.9

[1] Includes results attributable to a noncontrolling interest in MP GOM.

Geographic Information

	Certain long-lived assets at December 31 [1]			
(Millions of dollars)	United States	Canada	Other	Total
2023	**$ 6,555.0**	**$ 1,497.3**	**$ 172.8**	**$ 8,225.1**
2022	6,562.8	1,499.1	166.1	8,228.0
2021	6,371.4	1,566.9	189.6	8,127.9

[1] Certain long-lived assets at December 31 exclude 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 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 17 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 lessor. Purchase options also exist for certain leases.

Related Expenses

Expenses related to finance and operating leases included in the Consolidated Financial Statements are as follows:

		Year Ended December 31,	
(Thousands of dollars)	**Financial Statement Category**	**2023**	2022
Operating lease [1, 2]	Lease operating expenses	**$ 246,721**	$ 217,038
Operating lease [2]	Transportation, gathering and processing	**37,797**	39,669
Operating lease [2]	Selling and general expense	**9,859**	8,003
Operating lease [2]	Other operating expense	**675**	510
Operating lease [2]	Exploration expenses	**110,577**	10,019
Operating lease [2]	Property, plant and equipment	**204,595**	196,829
Operating lease [2]	Asset retirement obligations	**57,442**	11,190
Finance lease			
Amortization of asset	Depreciation, depletion and amortization	**1,505**	5,481
Interest on lease liabilities	Interest expense, net	**221**	254
Sublease income	Other income	**(1,402)**	(1,296)
Net lease expense		**$ 667,990**	$ 487,697

[1] *Variable lease expenses.* For the years ended December 31, 2023 and 2022, includes variable lease expenses of $36.7 million and $32.2 million, respectively, primarily related to additional volumes processed at a natural gas processing plant.

[2] *Short-term leases due within 12 months.* For the year ended December 31, 2023, includes $78.2 million in LOE, $29.4 million for "Transportation, gathering and processing", $80.3 million for "Exploration expenses, including undeveloped lease amortization", $1.6 million in "Selling and general expenses", $0.3 million in "Other operating expense", $112.7 million in "Property, plant and equipment, net" and $57.4 million in "Asset retirement obligations" relating to short-term leases due within 12 months. Expenses primarily relate to drilling rigs and other oil and natural gas field equipment. For the year ended December 31, 2022, includes $62.8 million in LOE, $31.5 million in "Transportation, gathering and processing", $8.8 million for "Exploration expenses, including undeveloped lease amortization, $0.7 million in "Selling and general expenses", $0.1 million in "Other operating expense", $125.4 million in "Property, plant and equipment, net" and $11.2 million in "Asset retirement obligations" relating to short-term leases due within 12 months. Expenses primarily relate to drilling rigs and other oil and natural gas field equipment.

Note T – Leases (Continued)

Maturity of Lease Liabilities

(Thousands of dollars)	Operating Leases	Finance Leases	Total
2024	$ 244,622	$ 1,069	$ 245,691
2025	82,596	1,069	83,665
2026	63,703	1,069	64,772
2027	62,066	1,069	63,135
2028	61,229	1,069	62,298
Remaining	499,501	265	499,766
Total future minimum lease payments	1,013,717	5,610	1,019,327
Less imputed interest	(254,032)	(1,372)	(255,404)
Present value of lease liabilities [1]	**$ 759,685**	**$ 4,238**	**$ 763,923**

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

Lease Term and Discount Rate

	December 31, 2023	December 31, 2022
Weighted average remaining lease term:		
Operating leases	**10 years**	9 years
Finance leases	**5 years**	6 years
Weighted average discount rate:		
Operating leases	**5.9 %**	5.9 %
Finance leases	**4.7 %**	4.7 %

Other Information

	Year Ended December 31,	
(Thousands of dollars)	**2023**	2022
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from operating leases	**$ 271,488**	$ 212,061
Operating cash flows from finance leases	**221**	254
Financing cash flows from finance leases	**622**	636
Right-of-use assets obtained in exchange for lease liabilities:		
Operating leases [1]	**$ 5,923**	$ 262,669

[1] For the year ended December 31, 2023, right-of-use assets obtained in exchange for lease liabilities primarily includes $4.5 million related to natural gas compressor units at various U.S. Onshore locations. December 31, 2022 includes $254.0 million related to an offshore drilling rig with a lease term of 24 months.

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 Natural 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 crude oil, condensate, natural gas liquids 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 judgmental decisions 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 2023 were $78.22 per barrel for NYMEX crude oil (WTI) and $2.64 per MCF for natural gas (Henry Hub). The average prices used for 2022 were $93.67 per barrel for NYMEX crude oil (WTI) and $6.36 per MCF for natural gas (Henry Hub). The average prices used for 2021 were $66.56 per barrel for NYMEX crude oil (WTI) and $3.60 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 with one decimal; totals within the tables may not add as a result of rounding. 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 natural gas liquids.

All crude oil, natural gas liquid reserves and natural gas reserves are from consolidated subsidiaries (including noncontrolling interest) 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 NATURAL 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, 2023.

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 2020 – 2023

	Equivalents			
(Millions of barrels of oil equivalent)	Total	United States	Canada	Other
Proved developed and undeveloped reserves:				
December 31, 2020	714.9	328.5	386.4	–
Revisions of previous estimates	(52.9)	35.6	(89.3)	0.8
Extensions and discoveries	109.4	18.2	91.3	–
Purchases of properties	7.4	1.6	5.8	–
Sales of properties	(0.7)	–	(0.7)	–
Production	(61.1)	(40.4)	(20.6)	(0.1)
December 31, 2021	716.9	343.4	372.8	0.7
Revisions of previous estimates	(23.6)	29.0	(52.8)	0.2
Improved recovery	5.3	5.3	–	–
Extensions and discoveries	80.1	20.6	59.5	–
Purchases of properties	5.0	5.0	–	–
Sales of properties	(4.4)	(4.4)	–	–
Production	(63.9)	(41.9)	(21.7)	(0.3)
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**
Sales of properties	**(5.2)**	**–**	**(5.2)**	**–**
Production	**(70.4)**	**(45.3)**	**(25.0)**	**(0.1)**
December 31, 2023 [1]	**739.5**	**311.1**	**415.5**	**12.9**
Proved developed reserves:				
December 31, 2020	410.8	230.3	180.5	–
December 31, 2021	419.2	241.9	176.8	0.6
December 31, 2022	436.0	264.2	171.3	0.5
December 31, 2023 [2]	**425.5**	**223.2**	**202.0**	**0.3**
Proved undeveloped reserves:				
December 31, 2020	304.1	98.2	205.9	–
December 31, 2021	297.7	101.6	196.0	0.1
December 31, 2022	279.4	92.8	186.5	0.1
December 31, 2023 [3]	**314.0**	**87.9**	**213.5**	**12.6**

[1] Includes proved reserves of 15.5 MMBOE, consisting of 14.0 MMBBL oil, 0.6 MMBBL NGLs and 5.3 BCF natural gas attributable to the noncontrolling interest in MP GOM.

[2] Includes proved developed reserves of 12.8 MMBOE, consisting of 11.7 MMBBL oil, 0.5 MMBBL NGLs and 3.8 BCF natural gas attributable to the noncontrolling interest in MP GOM.

[3] Includes proved undeveloped reserves of 2.7 MMBOE, consisting of 2.3 MMBBL oil, 0.1 MMBBL NGLs and 1.5 BCF natural gas attributable to the noncontrolling interest in MP GOM.

[4] Totals within the tables may not add as a result of rounding.

2023 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2023 resulted predominantly from lower commodity prices in the U.S. and performance adjustments in 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 Tupper Montney.

Extensions and discoveries - In 2023, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney, the Eagle Ford Shale in the U.S., and Other international.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its Placid Montney assets in Canada.

2022 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2022 resulted predominantly from increased royalty rates and accelerated royalty incentive payouts due to higher commodity prices in Tupper Montney. These negative revisions were partially offset by positive well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2022, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney and Kaybob Duvernay as well as in the U.S. at the Gulf of Mexico and Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the U.S. Gulf of Mexico and divested working interests in one field in the U.S. Gulf of Mexico and a portion of Eagle Ford Shale.

2021 Comments for Proved Equivalent Reserves Changes

Revisions of previous estimates - The equivalent reserves revisions in 2021 resulted predominantly from accelerated royalty incentive payouts due to higher commodity prices in Tupper Montney. These negative revisions were partially offset by positive revisions in the U.S. from higher commodity prices, which partially reversed the 2020 capital expenditure reduction and improved well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2021, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney as well as in the U.S. at the Eagle Ford Shale and the Gulf of Mexico.

Purchases and sales of properties - In 2021, the Company acquired incremental working interests in Terra Nova offshore Canada and in the U.S. Gulf of Mexico.

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 2020 – 2023

(Millions of barrels)	Total	United States	Canada	Other
Proved developed and undeveloped crude oil reserves:				
December 31, 2020	266.5	240.6	25.9	–
Revisions of previous estimates	39.3	31.1	7.5	0.7
Extensions and discoveries	14.1	13.5	0.6	–
Purchases of properties	6.4	1.3	5.2	–
Production	(34.9)	(31.5)	(3.3)	(0.1)
December 31, 2021	291.5	255.0	35.9	0.6
Revisions of previous estimates	23.4	19.9	3.3	0.2
Improved recovery	4.7	4.7	–	–
Extensions and discoveries	18.9	16.1	2.8	–
Purchases of properties	4.2	4.2	–	–
Sales of properties	(3.6)	(3.6)	–	–
Production	(35.5)	(32.7)	(2.5)	(0.3)
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**
Sales of properties	**(2.0)**	**–**	**(2.0)**	**–**
Production	**(37.9)**	**(35.6)**	**(2.2)**	**(0.1)**
December 31, 2023 [1]	**275.8**	**228.0**	**35.4**	**12.4**
Proved developed crude oil reserves:				
December 31, 2020	179.8	161.4	18.4	–
December 31, 2021	191.5	174.9	16.0	0.5
December 31, 2022	209.0	194.4	14.2	0.4
December 31, 2023 [2]	**186.3**	**163.7**	**22.3**	**0.3**
Proved undeveloped crude oil reserves:				
December 31, 2020	86.7	79.2	7.5	–
December 31, 2021	99.9	80.0	19.8	0.1
December 31, 2022	94.6	69.2	25.3	0.1
December 31, 2023 [3]	**89.5**	**64.3**	**13.1**	**12.1**

[1] Includes total proved reserves of 14.0 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 11.7 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 2.3 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[4] Totals within the tables may not add as a result of rounding.

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 U.S. Gulf of Mexico.

Extensions and discoveries - In 2023, proved oil reserves were added for drilling and expansion activities predominantly in the Eagle Ford Shale and Other international.

Purchases and sales of properties - In 2023, the Company divested a portion of its working interest in the Kaybob Duvernay and all of its Placid Montney assets in Canada.

2022 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The positive crude oil reserves revisions in 2022 resulted predominantly from improved well performance in the U.S. Gulf of Mexico and impacts of higher commodity prices in the U.S.

Extensions and discoveries - In 2022, proved oil reserves were added for drilling and expansion activities predominantly in the U.S. Gulf of Mexico and the Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the U.S. Gulf of Mexico and divested working interests in one field in the U.S. Gulf of Mexico and a portion of the Eagle Ford Shale.

2021 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates - The positive crude oil reserves revisions in 2021 resulted predominantly from impacts of higher commodity prices in the U.S., which partially reversed the 2020 capital expenditure reductions and improved well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2021, proved oil reserves were added for drilling and expansion activities predominantly in the U.S. at the Eagle Ford Shale and the Gulf of Mexico.

Purchases and sales of properties - In 2021, the Company acquired incremental working interests in Terra Nova offshore Canada and one field in the U.S. Gulf of Mexico.

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 2020 – 2023

(Millions of barrels)	Total	United States	Canada	Other
Proved developed and undeveloped NGL reserves:				
December 31, 2020	38.2	34.6	3.6	–
Revisions of previous estimates	1.4	1.4	–	–
Extensions and discoveries	2.5	2.4	0.1	–
Purchase of properties	0.1	0.1	–	–
Production	(3.8)	(3.4)	(0.4)	–
December 31, 2021	38.4	35.1	3.3	–
Revisions of previous estimates	4.4	3.9	0.5	–
Improved recovery	0.2	0.2	–	–
Extensions and discoveries	2.5	1.9	0.6	–
Purchases of properties	0.3	0.3	–	–
Sales of properties	(0.2)	(0.2)	–	–
Production	(3.9)	(3.6)	(0.3)	–
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**	**–**
Sales of properties	**(0.6)**	**–**	**(0.6)**	**–**
Production	**(4.1)**	**(3.8)**	**(0.3)**	**–**
December 31, 2023 [1]	**37.6**	**34.3**	**3.3**	**–**
Proved developed NGL reserves:				
December 31, 2020	28.7	25.5	3.2	–
December 31, 2021	28.4	25.6	2.8	–
December 31, 2022	29.7	27.4	2.3	–
December 31, 2023 [2]	**25.9**	**24.1**	**1.8**	**–**
Proved undeveloped NGL reserves:				
December 31, 2020	9.5	9.1	0.4	–
December 31, 2021	10.0	9.5	0.5	–
December 31, 2022	12.0	10.2	1.8	–
December 31, 2023 [3]	**11.7**	**10.2**	**1.5**	–

[1] Includes total proved reserves of 0.6 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[2] Includes proved developed reserves of 0.5 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.
[3] Includes proved undeveloped reserves of 0.1 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 3 – Summary of Proved Natural Gas Liquids Reserves Based on Average Prices for 2020 – 2023 (Continued)

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 U.S. Gulf of Mexico.

Extensions and discoveries - In 2023, proved NGL reserves were added for drilling and expansion activities predominantly in the U.S. at 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 Placid Montney assets in Canada.

2022 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The positive NGL reserves revisions in 2022 resulted predominantly from improved well performance in the U.S. Gulf of Mexico and the Eagle Ford Shale, as well as in Canada at Kaybob Duvernay.

Extensions and discoveries - In 2022, proved NGL reserves were added for drilling and expansion activities predominantly in the U.S. Gulf of Mexico and the Eagle Ford Shale, as well as in Canada at Tupper Montney and Kaybob Duvernay.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the U.S. Gulf of Mexico and divested working interests in one field in the U.S. Gulf of Mexico and a portion of the Eagle Ford Shale.

2021 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates - The positive NGL reserves revisions in 2021 resulted predominantly from impacts of higher commodity prices, which partially reversed the 2020 capital expenditure reductions and improved well performance in the U.S. Gulf of Mexico.

Extensions and discoveries - In 2021, proved NGL reserves were added for drilling and expansion activities predominantly in the U.S. at Eagle Ford Shale.

Purchases and sales of properties - In 2021, the Company acquired incremental working interests in the U.S. Gulf of Mexico.

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 2020 – 2023

(Billions of cubic feet)	Total	United States	Canada	Other
Proved developed and undeveloped natural gas reserves:				
December 31, 2020	2,461.0	319.5	2,141.5	–
Revisions of previous estimates	(562.1)	18.7	(581.0)	0.2
Extensions and discoveries	556.7	13.5	543.2	–
Purchases of properties	5.4	1.5	3.9	–
Sales of properties	(4.4)	–	(4.4)	–
Production	(134.2)	(32.8)	(101.4)	–
December 31, 2021	2,322.3	320.3	2,001.8	0.2
Revisions of previous estimates	(309.8)	30.7	(340.5)	–
Improved recovery	2.6	2.6	–	–
Extensions and discoveries	352.4	15.7	336.7	–
Purchases of properties	2.9	2.9	–	–
Sale of properties	(3.6)	(3.6)	–	–
Production	(146.9)	(33.7)	(113.2)	–
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**
Sales of properties	**(15.6)**	**–**	**(15.6)**	**–**
Production	**(170.1)**	**(35.1)**	**(135.0)**	**–**
December 31, 2023 [1,4]	**2,556.2**	**293.1**	**2,260.1**	**3.0**
Proved developed natural gas reserves:				
December 31, 2020	1,213.8	260.2	953.6	–
December 31, 2021	1,196.0	248.1	947.7	0.2
December 31, 2022	1,183.1	254.1	928.8	0.2
December 31, 2023 [2,4]	**1,279.3**	**212.4**	**1,066.7**	**0.2**
Proved undeveloped natural gas reserves:				
December 31, 2020	1,247.2	59.3	1,187.9	–
December 31, 2021	1,126.4	72.2	1,054.1	–
December 31, 2022	1,036.8	80.8	956.0	–
December 31, 2023 [3]	**1,276.9**	**80.7**	**1,193.4**	**2.8**

[1] Includes total proved reserves of 5.3 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

[2] Includes proved developed reserves of 3.8 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

[3] Includes proved undeveloped reserves of 1.5 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

[4] Includes proved natural gas reserves to be consumed in operations as fuel of 71.3 BCF, 41.9 BCF and 2.8 BCF for the U.S. Canada and Other, respectively, with 1.2 BCF attributable to the noncontrolling interest in MP GOM.

[5] Totals within the tables may not add as a result of rounding.

Schedule 4 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2016 – 2019 (Continued)

2023 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2023 resulted predominantly from lower commodity prices in the U.S. and performance adjustments in Tupper Montney and the Eagle Ford Shale. These negative revisions were partially offset by positive revisions in the U.S. Gulf of Mexico, as well as reduced royalty rates and delayed royalty incentive payouts resulting from lower commodity prices in Canada at Tupper Montney.

Extensions and discoveries - In 2023, proved natural gas reserves were added for drilling and expansion activities predominantly in Canada at 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 Placid Montney assets in Canada.

2022 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2022 resulted predominantly from increased royalty rates and accelerated royalty incentive payouts due to higher commodity prices in Canada at Tupper Montney.

Extensions and discoveries - In 2022, proved natural gas reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney, as well as in the U.S. Gulf of Mexico and Eagle Ford Shale.

Purchases and sales of properties - In 2022, the Company acquired incremental working interests in two producing fields in the U.S. Gulf of Mexico and divested working interests in one field in the U.S. Gulf of Mexico and a portion of Eagle Ford Shale.

2021 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates - The negative natural gas reserves revisions in 2021 resulted predominantly from accelerated royalty incentive payouts due to higher commodity prices at Tupper Montney.

Extensions and discoveries - In 2021, proved equivalent reserves were added for drilling and expansion activities predominantly in Canada at Tupper Montney, as well as in the U.S. at the Eagle Ford Shale and the Gulf of Mexico.

Purchases and sales of properties - In 2021, the Company acquired incremental working interests at Terra Nova offshore Canada and in the U.S. Gulf of Mexico.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 5 – Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada [1]	Other	Total
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	**166.5**	**0.4**	**57.0**	**223.9**
Property additions	**$ 671.3**	**$ 206.2**	**$ 13.1**	**$ 890.6**
Year ended December 31, 2022				
Property acquisition costs				
Unproved	$ 1.8	$ –	$ –	$ 1.8
Proved	128.5	–	–	128.5
Total acquisition costs	130.3	–	–	130.3
Exploration costs	42.2	0.8	70.3	113.3
Development costs	704.9	208.5	4.3	917.7
Total costs incurred	877.4	209.3	74.6	1,161.3
Charged to expense				
Dry hole expense	23.0	–	59.1	82.1
Geophysical and other costs	15.8	0.8	21.1	37.7
Total charged to expense	38.8	0.8	80.2	119.8
Property additions	$ 838.6	$ 208.5	$ (5.6)	$ 1,041.5
Year ended December 31, 2021				
Property acquisition costs				
Unproved	$ 8.8	$ –	$ –	$ 8.8
Proved	19.9	(20.4)	–	(0.5)
Total acquisition costs	28.7	(20.4)	–	8.3
Exploration costs	31.7	0.4	30.1	62.2
Development costs	513.2	102.4	3.7	619.3
Total costs incurred	573.6	82.4	33.8	689.8
Charged to expense				
Dry hole expense	17.3	–	–	17.3
Geophysical and other costs	13.1	0.4	19.3	32.8
Total charged to expense	30.4	0.4	19.3	50.1
Property additions	$ 543.2	$ 82.0	$ 14.5	$ 639.7

[1] 2021 Canada proved property acquisitions represents cash received from divesting partners on acquisition of an additional 7.525% working interest at Terra Nova as part of the sanction of an asset life extension project.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 6 – Results of Operations for Oil and Natural Gas Producing Activities [1]

(*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 (benefits)	**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**
Year ended December 31, 2022				
Revenues				
Crude oil and natural gas liquids sales	$ 3,210.3	$ 267.5	$ 22.8	$ 3,500.6
Natural gas sales	225.3	312.6	–	537.9
Sales of purchased natural gas	0.2	181.5	–	181.7
Total oil and natural gas revenues	3,435.8	761.6	22.8	4,220.2
Other operating revenues	25.4	1.3	–	26.7
Total revenues	3,461.2	762.9	22.8	4,246.9
Costs and expenses				
Lease operating expenses	522.7	155.1	1.5	679.3
Severance and ad valorem taxes	55.7	1.3	–	57.0
Transportation, gathering and processing	142.2	70.5	–	212.7
Costs of purchased natural gas	0.2	171.8	–	172.0
Exploration costs charged to expense	38.8	0.8	80.2	119.8
Undeveloped lease amortization	8.7	0.2	4.4	13.3
Depreciation, depletion and amortization	617.0	141.5	5.4	763.9
Accretion of asset retirement obligations	36.5	9.6	0.1	46.2
Selling and general expenses	20.4	21.9	2.2	44.5
Other expenses	126.3	12.4	3.1	141.8
Total costs and expenses	1,568.5	585.1	96.9	2,250.5
Results of operations before taxes	1,892.7	177.8	(74.1)	1,996.4
Income tax expense (benefit)	370.8	43.6	2.9	417.3
Results of operations	$ 1,521.9	$ 134.2	$ (77.0)	$ 1,579.1

[1] Results exclude corporate overhead, interest and discontinued operations. Results include 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 Natural Gas Producing Activities [1] (Continued)

(*Millions of dollars*)	United States	Canada	Other	Total
Year ended December 31, 2021				
Revenues				
Crude oil and natural gas liquids sales	$ 2,199.7	$ 228.9	$ 4.9	$ 2,433.5
Natural gas sales	121.8	245.9	–	367.7
Total oil and natural gas revenues	2,321.5	474.8	4.9	2,801.2
Other operating revenues	16.0	1.5	–	17.5
Total revenues	2,337.5	476.3	4.9	2,818.7
Costs and expenses				
Lease operating expenses	406.4	136.3	(3.2)	539.5
Severance and ad valorem taxes	39.6	1.6	–	41.2
Transportation, gathering and processing	126.5	60.5	–	187.0
Exploration costs charged to expense	30.4	0.4	19.3	50.1
Undeveloped lease amortization	11.1	0.2	7.6	18.9
Depreciation, depletion and amortization	616.5	163.8	1.8	782.1
Accretion of asset retirement obligations	36.9	9.7	–	46.6
Impairment of assets	–	171.3	18.0	189.3
Selling and general expenses	20.5	16.5	6.6	43.6
Other expenses	99.4	(66.2)	(2.2)	31.0
Total costs and expenses	1,387.3	494.1	47.9	1,929.3
Results of operations before taxes	950.2	(17.8)	(43.0)	889.4
Income tax expense (benefit)	183.9	(1.7)	(9.5)	172.7
Results of operations	$ 766.3	$ (16.1)	$ (33.5)	$ 716.7

[1] Results exclude corporate overhead, interest and discontinued operations. Results include 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 Natural Gas Reserves [1]

(*Millions of dollars*)	United States	Canada	Other	Total
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**
December 31, 2022				
Future cash inflows	$ 27,277.9	$ 12,360.2	$ 59.2	$ 39,697.3
Future development costs	(1,594.5)	(642.4)	(1.4)	(2,238.3)
Future production costs	(8,297.4)	(4,199.0)	(12.1)	(12,508.5)
Future income taxes	(2,606.8)	(1,788.7)	(5.4)	(4,400.9)
Future net cash flows	14,779.2	5,730.1	40.3	20,549.6
10% annual discount for estimated timing of cash flows	(5,709.8)	(3,015.6)	(11.0)	(8,736.4)
Standardized measure of discounted future net cash flows	$ 9,069.4	$ 2,714.5	$ 29.3	$ 11,813.2
December 31, 2021				
Future cash inflows	$ 18,449.1	$ 7,203.5	$ 44.0	$ 25,696.7
Future development costs	(1,164.3)	(521.1)	(1.5)	(1,686.8)
Future production costs	(7,140.6)	(3,525.8)	(9.1)	(10,675.4)
Future income taxes	(1,024.4)	(565.4)	(3.0)	(1,592.8)
Future net cash flows	9,119.9	2,591.3	30.4	11,741.6
10% annual discount for estimated timing of cash flows	(3,264.9)	(1,169.3)	(8.5)	(4,442.7)
Standardized measure of discounted future net cash flows	$ 5,855.1	$ 1,422.0	$ 21.9	$ 7,299.0

[1] Includes noncontrolling interest in MP GOM.
[2] Totals within the table may not add as a result of rounding.

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 Natural 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)	2023	2022	2021
Net changes in prices and production costs [2]	$ (5,845.6)	$ 4,812.2	$ 5,962.1
Net changes in development costs	(78.8)	(531.1)	(503.6)
Sales and transfers of oil and natural gas produced, net of production costs	(2,264.8)	(2,917.4)	(2,220.5)
Net change due to extensions and discoveries	770.4	1,223.5	908.5
Net change due to purchases and sales of proved reserves	(96.1)	102.1	63.1
Development costs incurred	703.7	769.3	619.3
Accretion of discount	1,393.3	802.6	267.2
Revisions of previous quantity estimates	(771.5)	1,652.9	277.1
Net change in income taxes	1,229.6	(1,399.9)	(692.8)
Net increase (decrease)	(4,959.8)	4,514.2	4,680.4
Standardized measure at January 1	11,813.2	7,299.0	2,618.6
Standardized measure at December 31	$ 6,853.4	$ 11,813.2	$ 7,299.0

1 Includes noncontrolling interest in MP GOM.

2 The average prices used for 2023 were $78.22 per barrel for NYMEX crude oil (WTI) and $2.64 per MCF for natural gas (Henry Hub). The average prices used for 2022 were $93.67 per barrel for NYMEX crude oil (WTI) and $6.36 per MCF for natural gas (Henry Hub). The average prices used for 2021 were $66.56 per barrel for NYMEX crude oil (WTI) and $3.60 per MCF for natural gas (Henry Hub).

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued
Schedule 8 – Capitalized Costs Relating to Oil and Natural Gas Producing Activities

(*Millions of dollars*)	United States	Canada	Other	Total
December 31, 2023				
Unproved oil and natural gas properties	**$ 337.3**	**$ 13.1**	**$ 49.7**	**$ 400.1**
Proved oil and natural gas properties	**15,868.4**	**4,716.0**	**153.7**	**20,738.1**
Gross capitalized costs	**16,205.7**	**4,729.1**	**203.4**	**21,138.2**
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	**(105.3)**	**–**	**(17.4)**	**(122.7)**
Proved oil and natural gas properties	**(9,552.9)**	**(3,233.7)**	**(42.8)**	**(12,829.4)**
Net capitalized costs	**$ 6,547.5**	**$ 1,495.4**	**$ 143.2**	**$ 8,186.1**
December 31, 2022				
Unproved oil and natural gas properties	$ 494.6	$ 19.2	$ 135.1	$ 648.9
Proved oil and natural gas properties	15,051.9	4,684.8	55.9	19,792.6
Gross capitalized costs	15,546.5	4,704.0	191.0	20,441.5
Accumulated depreciation, depletion and amortization				
Unproved oil and natural gas properties	(117.8)	–	(14.7)	(132.5)
Proved oil and natural gas properties	(8,873.6)	(3,208.0)	(41.3)	(12,122.9)
Net capitalized costs	$ 6,555.1	$ 1,496.0	$ 135.0	$ 8,186.1

Note: 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 [1]
Year ended December 31, 2023					
Revenue from contracts with customers	**$ 840.0**	**$ 812.9**	**$ 953.8**	**$ 842.2**	**$ 3,448.9**
Income (loss) from continuing operations before income taxes	**267.9**	**127.3**	**356.3**	**169.5**	**921.0**
Income (loss) from continuing operations	**214.0**	**92.5**	**278.2**	**140.5**	**725.2**
Net income (loss) including noncontrolling interest	**214.3**	**91.9**	**277.8**	**139.7**	**723.7**
Net income (loss) attributable to Murphy	**191.6**	**98.3**	**255.3**	**116.4**	**661.6**
Income (loss) from continuing operations per common share [2]					
Basic	**1.23**	**0.63**	**1.64**	**0.76**	**4.27**
Diluted	**1.22**	**0.62**	**1.63**	**0.75**	**4.23**
Net income (loss) per common share [2]					
Basic	**1.23**	**0.63**	**1.64**	**0.76**	**4.26**
Diluted	**1.22**	**0.62**	**1.63**	**0.75**	**4.22**
Cash dividend per common share	**0.275**	**0.275**	**0.275**	**0.275**	**1.100**
Year ended December 31, 2022					
Revenue from contracts with customers	$ 871.4	$ 1,196.2	$ 1,166.4	$ 986.1	$ 4,220.1
Income (loss) from continuing operations before income taxes	(81.9)	515.5	734.0	282.7	1,450.3
Income (loss) from continuing operations	(64.9)	410.4	574.5	220.8	1,140.8
Net income (loss) including noncontrolling interest	(65.5)	409.5	574.1	220.6	1,138.7
Net income (loss) attributable to Murphy	(113.3)	350.6	528.3	199.4	965.0
Income (loss) from continuing operations per common share [2]					
Basic	(0.73)	2.27	3.40	1.28	6.23
Diluted	(0.73)	2.24	3.36	1.26	6.14
Net income (loss) per common share [2]					
Basic	(0.73)	2.26	3.40	1.28	6.22
Diluted	(0.73)	2.23	3.36	1.26	6.13
Cash dividend per common share	0.150	0.175	0.250	0.250	0.825

[1] Revenue from contracts with customers, “Income from continuing operations before income taxes”, “Income from continuing operations” and “Net income including noncontrolling interest” include 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE II - VALUATION ACCOUNTS AND RESERVES

(*Millions of dollars*)	Balance at January 1	Charged to Expense	Deductions	Other	Balance at December 31
2023					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 1.6**	**$ –**	**$ –**	**$ –**	**$ 1.6**
Deferred tax asset valuation allowance	**136.0**	**10.9**	**–**	**–**	**146.9**
2022					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	$ –	$ –	$ –	$ 1.6
Deferred tax asset valuation allowance	111.2	24.8	–	–	136.0
2021					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	$ –	$ –	$ –	$ 1.6
Deferred tax asset valuation allowance	106.4	4.8	–	–	111.2

DEFINITIONS

AECO - Alberta Energy Company and is the Canadian benchmark price for natural gas
AIP - Annual Incentive Plan
ARO - asset retirement obligation
Bbl - barrel
BCF - billion cubic feet
BOE - barrels of oil equivalent
BOEM - U.S. Bureau of Ocean Energy Management
BOEPD - barrel of oil equivalent per day
BSEE - U.S. Bureau of Safety and Environmental Enforcement
CAD or C$ - Canadian dollar
CRSU - cash-settled restricted time-based stock unit
DD&A - depreciation, depletion and amortization
Deepwater - offshore location in greater than 1,000 feet of water
DE&I - Diversity, Equity and Inclusion
Downstream - refining and marketing operations
Dry hole - an exploratory well that does not find oil or natural gas in commercial quantities
E&P - exploration and production
EBITDA - earnings before interest, taxes, depreciation and amortization
EPA - U.S. Environmental Protection Agency
Exploratory well - a well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive by another reservoir
FPS - floating production system
GAAP - U.S. Generally Accepted Accounting Principles
GHG - greenhouse gas
Hyrdocarbons - organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products
LOE - lease operating expense
MCF - thousand cubic feet
MMBBL - million barrels of oil
MMBOE - million barrels of oil equivalent
MMBTU - million British thermal units
MMCF - million cubic feet
MPGOM - MP Gulf of Mexico, LLC
NCI - noncontrolling interest
Net acres or net wells - the portions of gross acres or gross wells owned by the Company
NGL - natural gas liquid
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
PAI - Petrobras America Inc.
PCAOB - Public Company Accounting Oversight Board

DEFINITIONS - Continued

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

PSU - performance-based restricted stock unit

QRE - qualified reserve estimator

RCF - revolving credit facility

RSU - time-based restricted stock unit

SAR - stock appreciation right

SEAL - Sergipe-Alagoas Basin

SEC - U.S. Securities and Exchange Commission

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

SOFR - Secured Overnight Financing Rate

TCFD - Task Force on Climate-related Financial Disclosures

Upstream - oil and natural gas exploration and production operations, including synthetic oil operations

USD - United States dollar

VIE - variable interest entity

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

MURPHY OIL CORPORATION
COMPENSATION RECOUPMENT POLICY

This Murphy Oil Corporation Compensation Recoupment Policy (the "**Policy**") has been adopted by the Board of Directors (the "**Board**") of Murphy Oil Corporation (the "**Company**") on October 4, 2023. This Policy provides for the recoupment of certain executive compensation in the event of an accounting restatement resulting from material noncompliance with financial reporting requirements under U.S. federal securities laws in accordance with the terms and conditions set forth herein.

1. Definitions. For the purposes of this Policy, the following terms shall have the meanings set forth below.

(a) "**Code**" means the U.S. Internal Revenue Code of 1986, as amended.

(b) "**Committee**" means the Compensation Committee of the Board or any successor committee thereof.

(c) "**Covered Compensation**" means any Incentive-based Compensation "received" by an Executive Officer during the applicable Recoupment Period; *provided* that:

(i) such Covered Compensation was received by such Executive Officer (A) after the Effective Date, (B) after commencement of service as an Executive Officer and (C) while the Company had a class of securities publicly listed on a United States national securities exchange; and

(ii) such Executive Officer served as an Executive Officer at any time during the performance period applicable to such Incentive-based Compensation.

For purposes of this Policy, Incentive-based Compensation is "**received**" by an Executive Officer during the fiscal period in which the Financial Reporting Measure applicable to such Incentive-based Compensation (or portion thereof) is attained, even if the payment or grant of such Incentive-based Compensation is made thereafter.

(d) "**Effective Date**" means the date on which Section 303A.14 of the NYSE Listed Company Manual becomes effective.

(e) "**Exchange Act**" means the U.S. Securities Exchange Act of 1934, as amended.

(f) "**Executive Officer**" means, those persons who are designated by the Board as an "officer" of the Company as such term is defined in Rule 16a-1(f) under the Exchange Act. Both current and former Executive Officers are subject to this Policy in accordance with its terms.

(g) "**Financial Reporting Measure**" means any (i) measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, (ii) stock price measure or (iii) total shareholder return measure (and any measures that are derived wholly or in part from any measure referenced in clause (i), (ii) or (iii) above). For the avoidance of doubt, any such measure does not need to be presented within the Company's financial statements or included in a filing with the U.S. Securities and Exchange Commission to constitute a Financial Reporting Measure.

(h) "**Financial Restatement**" means a required restatement of the Company's financial statements due to the Company's material noncompliance with any financial reporting requirement under U.S. federal securities laws that is required in order to correct:

(i) an error in previously issued financial statements that is material to the previously issued financial statements; or

(ii) an error that would result in a material misstatement if (A) the error were corrected in the current period or (B) left uncorrected in the current period.

For purposes of this Policy, a Financial Restatement shall not be deemed to occur in the event of a revision of the Company's financial statements due to an out-of-period adjustment (i.e., when the error is immaterial to the previously issued financial statements and the correction of the error is also immaterial to the current period) or a retrospective (1) application of a change in accounting principles; (2) revision to reportable segment information due to a change in the structure of the Company's internal organization; (3) reclassification due to a discontinued operation; (4) application of a change in reporting entity, such as from a reorganization of entities under common control; or (5) revision for stock splits, reverse stock splits, stock dividends or other changes in capital structure.

(i) "**Incentive-based Compensation"** means any compensation (including, for the avoidance of doubt, any cash or equity or equity-based compensation, whether deferred or current) that is granted, earned and/or vested based wholly or in part upon the achievement of a Financial Reporting Measure. For purposes of this Policy, "Incentive-based Compensation" shall also be deemed to include any amounts which were determined based on (or were otherwise calculated by reference to) Incentive-based Compensation (including, without limitation, any amounts under any long-term disability, life insurance or supplemental retirement or severance plan or agreement or any notional account that is based on Incentive-based Compensation, as well as any earnings accrued thereon).

(j) "**NYSE**" means the New York Stock Exchange, or any successor thereof.

(k) "**Recoupment Period**" means the three fiscal years completed immediately preceding the date of any applicable Recoupment Trigger Date. Notwithstanding the foregoing, the Recoupment Period additionally includes any transition period (that results from a change in the Company's fiscal year) within or immediately following those three completed fiscal years, provided that a transition period between the last day of the Company's previous fiscal year end and the first day of its new fiscal year that comprises a period of nine (9) to twelve (12) months would be deemed a completed fiscal year.

(l) "**Recoupment Trigger Date**" means the earlier of (i) the date that the Board (or a committee thereof or the officer(s) of the Company authorized to take such action if Board action is not required) concludes, or reasonably should have concluded, that the Company is required to prepare a Financial Restatement, and (ii) the date on which a court, regulator or other legally authorized body directs the Company to prepare a Financial Restatement.

2. Recoupment of Erroneously Awarded Compensation.

(a) In the event of a Financial Restatement, if the amount of any Covered Compensation received by an Executive Officer (the "**Awarded Compensation**") exceeds the amount of such Covered Compensation that would have otherwise been received by such Executive Officer if calculated based on the Financial Restatement (the "**Adjusted Compensation**"), the Company shall reasonably promptly recover from such Executive Officer an amount equal to the excess of the Awarded Compensation over the Adjusted Compensation, each calculated on a pre-tax basis (such excess amount, the "**Erroneously Awarded Compensation**").

(b) If (i) the Financial Reporting Measure applicable to the relevant Covered Compensation is stock price or total shareholder return (or any measure derived wholly or in part from either of such measures) and (ii) the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the Financial Restatement, then the amount of Erroneously Awarded Compensation shall be determined (on a pre-tax basis) based on the Company's reasonable estimate of the effect of the Financial Restatement on the Company's stock price or total shareholder return (or the derivative measure thereof) upon which such Covered Compensation was received.

(c) For the avoidance of doubt, the Company's obligation to recover Erroneously Awarded Compensation is not dependent on (i) if or when the restated financial statements are filed or (ii) any fault of any Executive Officer for the accounting errors or other actions leading to a Financial Restatement.

(d) Notwithstanding anything to the contrary in Sections 2(a) through (c) hereof, the Company shall not be required to recover any Erroneously Awarded Compensation if both (x) the conditions set forth in either of the following clauses (i) or (ii) are satisfied and (y) the Committee (or a majority of the independent directors serving on the Board) has determined that recovery of the Erroneously Awarded Compensation would be impracticable:

(i) the direct expense paid to a third party to assist in enforcing the recovery of the Erroneously Awarded Compensation under this Policy would exceed the amount of such Erroneously Awarded Compensation to be recovered; *provided* that, before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation pursuant to this Section 2(d), the Company shall have first made a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) to make such recovery and provide that documentation to the NYSE;

(ii) recovery of the Erroneously Awarded Compensation would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of Sections 401(a)(13) or 411(a) of the Code.

(e) The Company shall not indemnify any person (including, without limitation, any Executive Officer), directly or indirectly, for any losses that such person may incur in connection with the recovery of Erroneously Awarded Compensation pursuant to this Policy, including through the payment of insurance premiums or gross-up payments.

(f) The Committee shall determine, in its sole discretion, the manner and timing in which any Erroneously Awarded Compensation shall be recovered from an Executive Officer in accordance with applicable law, including, without limitation, by (i) requiring reimbursement of Covered Compensation previously paid in cash; (ii) seeking recovery of any gain realized on the vesting, exercise, settlement, sale, transfer or other disposition of any equity or equity-based awards; (iii) offsetting the Erroneously Awarded Compensation amount from any compensation otherwise owed by the Company or any of its affiliates to the Executive Officer; (iv) cancelling outstanding vested or unvested equity or equity-based awards; and/or (v) taking any other remedial and recovery action permitted by applicable law. For the avoidance of doubt, except as set forth in Section 2(d), in no event may the Company accept an amount that is less than the amount of Erroneously Awarded Compensation; *provided* that, to the extent necessary to avoid any adverse tax consequences to the Executive Officer pursuant to Section 409A of the Code, any offsets against amounts under any nonqualified deferred compensation plans (as defined under Section 409A of the Code) shall be made in compliance with Section 409A of the Code.

3. Administration. This Policy shall be administered by the Committee. All decisions of the Committee shall be final, conclusive and binding upon the Company and the Executive Officers, their beneficiaries, heirs, executors, administrators and any other legal representative. The Committee shall have full power and authority to (i) administer and interpret this Policy; (ii) correct any defect, supply any omission and reconcile any inconsistency in this Policy; and (iii) make any other determination and take any other action that the Committee deems necessary or desirable for the administration of this Policy and to comply with applicable law (including Section 10D of the Exchange Act) and applicable stock market or exchange rules and regulations. Notwithstanding anything to the contrary contained herein, to the extent permitted by Section 10D of the Exchange Act and Section 303A.14 of the NYSE Listed Company Manual, the Board may, in its sole discretion, at any time and from time to time, administer this Policy in the same manner as the Committee.

4. Amendment/Termination. Subject to Section 10D of the Exchange Act and Section 303A.14 of the NYSE Listed Company Manual, this Policy may be amended or terminated by the Committee at any time. To the extent that any applicable law, or stock market or exchange rules or regulations require recovery of Erroneously Awarded Compensation in circumstances in addition to those specified herein, nothing in this Policy shall be deemed to limit or restrict the right or obligation of the Company to recover Erroneously Awarded Compensation to the fullest extent required by such applicable law, stock market or exchange rules and regulations. Unless otherwise required by applicable law, this Policy shall no longer be effective from and after the date that the Company no longer has a class of securities publicly listed on a United States national securities exchange.

5. Interpretation. Notwithstanding anything to the contrary herein, this Policy is intended to comply with the requirements of Section 10D of the Exchange Act and Section 303A.14 of the NYSE Listed Company Manual (and any applicable regulations, administrative interpretations or stock market or exchange rules and regulations adopted in connection therewith). The provisions of this Policy shall be interpreted in a manner that satisfies such requirements and this Policy shall be operated accordingly. If any provision of this Policy would otherwise frustrate or conflict with this intent, the provision shall be interpreted and deemed amended so as to avoid such conflict.

6. Other Compensation Clawback/Recoupment Rights. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies, rights or requirements with respect to the clawback or recoupment of any compensation that may be available to the Company pursuant to the terms of any other recoupment or clawback policy of the Company (or any of its affiliates) that may be in effect from time to time, any provisions in any employment agreement, offer letter, equity plan, equity award agreement or similar plan or agreement, and any other legal remedies available to the Company, as well as applicable law, stock market or exchange rules, listing standards or regulations; *provided*, *however*, that any amounts recouped or clawed back under any other policy that would be recoupable under this Policy shall count toward any required clawback or recoupment under this Policy and vice versa.

7. Exempt Compensation. Notwithstanding anything to the contrary herein, the Company has no obligation to seek recoupment of amounts paid to an Executive Officer which are granted, vested or earned based solely upon the occurrence or non-occurrence of nonfinancial events. Such exempt compensation includes, without limitation, base salary, time-vesting awards, compensation awarded on the basis of the achievement of metrics that are not Financial Reporting Measures or compensation awarded solely at the discretion of the Committee or the Board, *provided* that such amounts are in no way contingent on, and were not in any way granted on the basis of, the achievement of any Financial Reporting Measure performance goal.

8. Miscellaneous.

(a) Any applicable award agreement or other document setting forth the terms and conditions of any compensation covered by this Policy shall be deemed to include the restrictions imposed herein and incorporate this Policy by reference and, in the event of any inconsistency, the terms of this Policy will govern. For the avoidance of doubt, this Policy applies to all compensation that is received on or after the Effective Date, regardless of the date on which the award agreement or other document setting forth the terms and conditions of the Executive Officer's compensation became effective or was first granted or awarded, including, without limitation, compensation received under the: Murphy Oil Corporation Annual Incentive Plan; Murphy Oil Corporation 2012 Long-Term Incentive Plan, as amended; Murphy Oil Corporation 2018 Long-Term Incentive Plan, as amended; Murphy Oil Corporation 2020 Long-Term Incentive Plan and any successor plans to each of the foregoing.

(b) This Policy shall be binding and enforceable against all Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representatives.

(c) All issues concerning the construction, validity, enforcement and interpretation of this Policy and all related documents, including, without limitation, any employment agreement, offer letter, equity award agreement or similar agreement, shall be governed by, and construed in accordance with, the laws of the State of Delaware, without giving effect to any choice of law or conflict of law rules or provisions (whether of the State of Delaware or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of Delaware.

(d) The Executive Officers, their beneficiaries, heirs, executors, administrators and any other legal representative and the Company shall initially attempt to resolve all claims, disputes or controversies arising under, out of or in connection with this Policy by conducting good faith negotiations amongst themselves. To ensure the timely and economical resolution of disputes that arise in connection with this Policy, the federal and state courts sitting within the State of Delaware shall be the sole and exclusive forums for any and all disputes, claims, or causes of action arising from or relating to the enforcement, performance or interpretation of this Policy. The Executive Officers, their beneficiaries, heirs, executors, administrators and any other legal representative and the Company, shall not commence any suit, action or other proceeding arising out of or based upon this Agreement except in the United States District Court for the District of Delaware or any Delaware court, and hereby waive, and agree not to assert, by way of motion, as a defense, or otherwise, in any such suit, action or proceeding, any claim that such party is not subject to the jurisdiction of the above-named courts, that its property is exempt or immune from attachment or execution, that the suit, action or proceeding is brought in an inconvenient forum, that the venue of the suit, action or proceeding is improper or that this Policy or the subject matter hereof may not be enforced in or by such courts. To the fullest extent permitted by law, the Executive Officers, their beneficiaries, heirs, executors, administrators, and any other legal representative, and the Company, shall waive (and shall hereby be deemed to have waived) the right to resolve any such dispute through a trial by jury.

(e) If any provision of this Policy is determined to be unenforceable or invalid under any applicable law, such provision will be applied to the maximum extent permitted by applicable law and shall automatically be deemed amended in a manner consistent with its objectives to the extent necessary to conform to any limitations required under applicable law.

EXHIBIT 10.30

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 2020 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 receive the pro-rata number of Target RSUs earned for performance completed 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 employee of the Company who is (i) the Chief Executive Officer of the Company (the "CEO"), (ii) an employee who reports directly to the CEO, or (iii) a named executive officer of the Company (a "Named Executive Officer"), in each case, 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 2027 unless such Change in Control also qualifies as a "change in control event" as determined under Section 409A.

(e) If the Grantee is an employee of the Company who is (i) the CEO, (ii) an employee who reports directly to the CEO, or (iii) a Named Executive Officer, in each case, 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, "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 Measures" for this Award are: (i) 80% of the Target RSUs (the "TSR Units") shall be based on and subject to the achievement of the Company's total shareholder return ("TSR") over the Performance Measurement Period compared to the TSR of the Company's peer group, and (ii) 20% of the Target RSUs (the "EBITDA/ACE Units") shall be based on and subject to the achievement of the amount determined by dividing (a) the sum of the Company's cumulative earnings before interest, tax, depreciation and amortization for each of the three years in the Performance Measurement Period (Cumulative EBITDA), by (b) the sum of the Company's average capital employed for each of the three years in the Performance Measurement Period (ACE). The number of Target RSUs earned (the "Payout Percentage") is detailed in the tables below.

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

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

   The Payout Percentage in respect of the TSR Units will be interpolated for points between the Threshold and Maximum performance levels. Notwithstanding the foregoing, if the Company's TSR over the Performance Measurement Period is less than 0%, the Payout Percentage shall not exceed 100%.

   b. EBITDA/ACE Performance Measure. The number of EBITDA/ACE Units earned will be based on the Company's achievement of the amount determined by dividing the Cumulative EBITDA by the ACE, as defined above, for the Performance Measurement Period, as set forth in the table below:

EBITDA/ACE Performance Level	**Payout Percentage**
Below [·]%	0%
[·]% (Threshold)	50%
[·]% (Target)	100%
[·]% or Above (Maximum)	200%

   The Payout Percentage in respect of the EBITDA/ACE Units will be interpolated for points between the Threshold and Maximum performance levels.

   c. Performance Measurement Period. The "Performance Measurement Period" under this Award is January 1, 2024 through December 31, 2026.

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 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 (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 2020 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 meanings 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 each equal in value to one share of Common Stock (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 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 Shares will be issued, less any Shares deducted for applicable withholding taxes; *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 or she will forfeit this Award.

(c) In the event of the Grantee's death, disability or retirement (as determined in accordance with the Plan) prior to the Vesting Date, any then outstanding Units pursuant to this Award shall vest on the date of the Grantee's 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 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 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 (i) the Chief Executive Officer of the Company (the "CEO"), (ii) an employee of the Company who reports directly to the CEO, or (iii) a named executive officer of the Company (the "Named Executive Officer") 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 Units granted will be deemed to be earned upon such Change in Control; *provided*, *however*, that no payment will be made until the first quarter of 2027 unless such Change in Control also qualifies as a "change in control event" as determined under Section 409A.

(e) If the Grantee is (i) the CEO, (ii) an employee of the Company who reports directly to the CEO, or (iii) a Named Executive Officer 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 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. 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 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, "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 issuance of Shares underlying the Units, 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 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.

5. 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.

6. The Grantee shall not be eligible to receive any dividends or other distributions paid with respect to the Units 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 this Award. Any such payment (unadjusted for interest) shall be made in whole Shares, valued as of the date that this Award vests in accordance with Section 2 above, subject to 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 and/or recoupment in accordance with the terms of the Recoupment Policy or such other applicable clawback or recoupment arrangements or policies.

8. The Plan and this Agreement are administered by the 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 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______________________________

EXHIBIT 10.32

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 2020 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 (i) the Chief Executive Officer of the Company (the "CEO"), (ii) an employee of the Company who reports directly to the CEO, or (iii) a named executive officer of the Company (the "Named Executive Officer") 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 (i) the CEO, (ii) an employee of the Company who reports directly to the CEO, or (iii) a Named Executive Officer 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 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.

(h) 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 ________________________________

EXHIBIT 10.33

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 2020 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; provided that, except as set forth in Section 2(c) below, the Grantee is employed by the Company on the Vesting Date.

(b) In the event that the Grantee's employment terminates anytime prior to the Vesting Date, except for reason of death, disability or retirement (as determined by the Plan), he/she will forfeit this Award.

(c) In the event of the Grantee's death, disability or retirement prior to the Vesting Date, any then outstanding Units pursuant to this Award shall vest on the date of the Grantee's 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 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 following the date of the Grantee's termination of employment.

3. The Award will fully vest and 100 percent (100%) of the Units granted will be deemed to be earned as of the date of a Change in Control and the Grantee will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as soon as reasonably practicable following the date of the Change in Control, less applicable withholding taxes; provided, however, that no payment will be made until the original Vesting Date unless the Change in Control also qualifies as a "change in control event" as determined under Section 409A.

4. 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.

5. 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.

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

7. 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 payment of the Award. Any such payment (unadjusted for interest) shall be made in cash, less 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 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 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 ______________________________

EXHIBIT 10.34

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 2020 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; provided that, except as set forth in Section 2(c) below, the Grantee is employed by the Company on the Vesting Date.

(b) In the event that the Grantee's employment terminates any time prior to the Vesting Date, except for reason of death, disability or retirement (as determined by the Plan) or a Reduction in Force (as defined below), he/she will forfeit this Award.

(c) In the event of the Grantee's termination of employment due to (i) the Grantee's death, disability or retirement or (ii) a Reduction in Force prior to the Vesting Date, any then outstanding Units pursuant to this Award shall vest on the date of the Grantee's 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 following the date of the Grantee's termination of employment.

(d) 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. The Award will fully vest and 100 percent (100%) of the Units granted will be deemed to be earned as of the date of a Change in Control and the Grantee will be paid in cash the Fair Market Value of the Shares underlying his/her vested Units as soon as reasonably practicable following the date of the Change in Control, less applicable withholding taxes; provided, however, that no payment will be made until the original Vesting Date unless the Change in Control also qualifies as a "change in control event" as determined under Section 409A.

4. 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.

5. 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.

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

7. 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 payment of the Award. Any such payment (unadjusted for interest) shall be made in cash, less 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 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 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, 2023

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
1. El Dorado Contractors	Delaware	100.00
2. El Dorado Exploracion y Produccion, S. de. R.L. de C.V. (see company F.2.b(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
1. Murphy Building Corporation	Delaware	100.00
2. Murphy Exploration & Production Company - International	Delaware	100.00
a. Canam Offshore Limited	Bahamas	100.00
(1) Canam Brunei Oil Ltd.	Bahamas	100.00
(2) Murphy Peninsular Malaysia Oil Co., Ltd.	Bahamas	100.00
(3) Murphy Cuu Long Tay Oil Co., Ltd.	Bahamas	100.00
b. El Dorado Exploration, S.A.	Delaware	100.00
(1) El Dorado Exploracion y Produccion, S. de. R.L. de C.V.	Mexico	90.00
c. Murphy Asia Oil Co., Ltd.	Bahamas	100.00
d. Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda. (see company j.(1) below)	Brazil	90.00
e. Murphy Cuu Long Bac Oil Co., Ltd.	Bahamas	100.00
f. Murphy Dai Nam Oil Co., Ltd.	Bahamas	100.00
g. Murphy Equatorial Guinea Oil Co., Ltd.	Bahamas	100.00
h. Murphy Luderitz Oil Co., Ltd.	Bahamas	100.00
i. Murphy Nha Trang Oil Co., Ltd.	Bahamas	100.00
j. Murphy Overseas Ventures Inc.	Delaware	100.00
(1) Murphy Brasil Exploracao e Producao de Petroleo e Gas Ltda.	Brazil	10.00
k. Murphy Phuong Nam Oil Co., Ltd.	Bahamas	100.00
l. Murphy Semai IV Ltd.	Bahamas	100.00
m. Murphy South Barito, Ltd.	Bahamas	100.00
n. Murphy-Spain Oil Company	Delaware	100.00
o. Murphy West Africa, Ltd.	Bahamas	100.00
p. Murphy Worldwide, Inc.	Delaware	100.00
q. Murphy Offshore Oil Co. Ltd.	Bahamas	100.00
r. Murphy Netherlands Holdings B.V.	Netherlands	100.00
(1) Murphy Sur, S. de R. L. de C.V. (see company r(2)a. below)	Mexico	0.01
(2) Murphy Netherlands Holdings II B.V.	Netherlands	100.00
a. Murphy Sur, S. de R. L. de C.V.	Mexico	99.99

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
s. 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 57 Oil Pty. Ltd.	Western Australia	100.00
(3) Murphy Australia AC/P 58 Oil Pty. Ltd.	Western Australia	100.00
(4) Murphy Australia AC/P 59 Oil Pty. Ltd.	Western Australia	100.00
(5) Murphy Australia EPP43 Oil Pty. Ltd.	Western Australia	100.00
(6) Murphy Australia WA-481-P Oil Pty. Ltd.	Western Australia	100.00
t. Murphy CI-102 Oil Co., Ltd	Bahamas	100.00
u. Murphy CI-103 Oil Co., Ltd	Bahamas	100.00
v. Murphy CI-502 Oil Co., Ltd	Bahamas	100.00
w. Murphy CI-531 Oil Co., Ltd	Bahamas	100.00
x. Murphy CI-709 Oil Co., Ltd	Bahamas	100.00
3. Murphy Exploration & Production Company - USA	Delaware	100.00
a. MP Gulf of Mexico, LLC	Delaware	80.00
G. Murphy Oil Company Ltd.	Canada	100.00
1. Murphy Canada Holding ULC	AULC	100.00
2. Murphy Canada, Ltd.	Canada	100.00
H. New Murphy Oil (UK) Corporation	Delaware	100.00
1. Murphy Petroleum Limited	England	100.00
a. 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. 333-256048 and 333-241837) on Form S-8 and in the registration statement (No. 333-260287) on Form S-3 of our reports dated February 23, 2024, with respect to the consolidated financial statements and financial statement Schedule II of Murphy Oil Corporation and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 23, 2024

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
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. 333-256048 and 333-241837) on Form S-8, the Registration Statement (File No. 333-260287) on Form S-3 of Murphy Oil Corporation, and of the reference to our reports regarding certain assets in the United States effective December 31, 2023 and dated January 17, 2024 for Murphy Oil Corporation, which appears in the December 31, 2023 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 23, 2024

McDANIEL

Jeffrey 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 Kaybob Duvernay and Greater Tupper Montney Projects located within the Province of British Columbia and Alberta, Canada, effective December 31, 2023 and dated January 25, 2024 in the Murphy Oil Corporation Form 10-K for the year ended December 31, 2023, Registration Statement Form S-8, No. 333-256048 and Registration Statement Form S-3, No. 333-260287 and in any related prospectus, including any reference to our firm under the heading "Experts" in such prospectus.

McDaniel & Associates Consultants Ltd.

/s/ Jared W. B. Wynveen

Jared W. B. Wynveen, P. Eng.
Executive Vice President

February 23, 2024
APEGA PERMIT NUMBER: P3145

Exhibit 23.4

Gaffney, Cline & Associates
(Consultants) Pte. Ltd.
150 Beach Road
#20-01/02 Gateway West
Singapore 189720

Tel: +65 6225 6951

UEN: 198701453N

Gaffney Cline

February 23, 2024

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

Dear Jeffrey,

Consent to Release GaffneyCline Report

We hereby consent to the reference of our firm and to the use of our report conducting an audit of the Lac Da Vang property located in the south-east corner of Block 15-1/05 in the Cuu Long Basin on the continental shelf, offshore of southern Vietnam, effective December 31, 2023 and dated January 26, 2024 in the Murphy Oil Corporation Form 10-K for the year ended December 31, 2023, Registration Statement Form S-8, No. 333-256048 and Registration Statement Form S-3, No. 333-260287 and in any related prospectus, including any reference to our firm under the heading “Experts” in such prospectus.

Yours sincerely,

Gaffney, Cline & Associates (Consultants) Pte Ltd

D. Peacock

Doug Peacock
Senior Director

EXHIBIT 31.1

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

I, Roger W. Jenkins, 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 23, 2024

/s/ Roger W. Jenkins

Roger W. Jenkins
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 23, 2024

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

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, 2023 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Roger W. Jenkins 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 23, 2024

/s/ Roger W. Jenkins
Roger W. Jenkins
Principal Executive Officer

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

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to Certain

Leasehold Interests

U.S. Onshore

Gulf of Mexico

SEC Parameters

As of

December 31, 2023

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

[SEAL]

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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

January 17, 2024

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, 2023 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 7, 2023 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 U.S. Onshore 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, 2023. For the Gulf of Mexico (GOM) properties, the estimated reserves shown herein exclude the net reserves attributable to Murphy's leasehold interests in the Murphy and Petrobras GOM JV (MPGOM). The net reserves attributable to the MPGOM assets are included in a separate Ryder Scott report dated January 27, 2024. The properties reviewed by Ryder Scott incorporate Murphy's reserves determinations and are located onshore in the state of Texas and Louisiana and in the federal waters offshore Louisiana.

The combined U.S. Onshore and GOM properties reviewed by Ryder Scott account for a portion of Murphy's total net proved reserves as of December 31, 2023. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott in this report addresses 31.3 percent of the total proved net reserves of Murphy on a barrel of oil equivalent, BOE basis as of December 31, 2023.

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.

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

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, 2023 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, 2023, 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
As of December 31, 2023

	Proved		
	Developed	Undeveloped	Total Proved
Audited by Ryder Scott			
U.S. Onshore			
Net Reserves			
Oil/Condensate – Mbbl	70,322	35,805	106,127
Plant Products – Mbbl	16,335	7,579	23,914
Gas – MMcf	136,309	55,671	191,980
MBOE	109,375	52,663	162,038
Gulf of Mexico (GOM)			
Net Reserves			
Oil/Condensate – Mbbl	33,838	15,953	49,791
Plant Products – Mbbl	5,305	2,024	7,329
Gas – MMcf	54,812	17,404	72,216
MBOE	48,278	20,878	69,156

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 62,001 MMcf, or 6.4 percent of the total U.S. Onshore net MBOE and 3,113 MMcf, or 0.75 percent of the total GOM 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 2023, 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 2023. 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, 2023 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-Offshore	Oil/Condensate	WTI Cushing	$78.22/Bbl	$78.24/BBL	$78.24/BBL
	NGLs	WTI Cushing	$78.22/Bbl	$16.11/BBL	$16.11/BBL
	Gas	Henry Hub	$2.64/MMBTU	$2.72/MCF	$2.83/MCF
United States-Onshore	Oil/Condensate	WTI Cushing	$78.22/Bbl	$77.41/BBL	$77.41/BBL
	NGLs	WTI Cushing	$78.22/Bbl	$21.51/BBL	$21.51/BBL
	Gas	Henry Hub	$2.64/MMBTU	$1.56/MCF	$2.30/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, 2023. 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, 2023, 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, 2023 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, 2023 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

/s/ Eric T. Nelson

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

[SEAL]

ETN (LPC)/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 2023 continuing education hours, Mr. Nelson attended over 20 hours of training during 2023 covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, 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 17 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

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

PREAMBLE

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

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

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

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

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

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

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

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

RESERVES (SEC DEFINITIONS)

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

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

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

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

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

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

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

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

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

UNDEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

EXHIBIT 99.2

MURPHY OIL CORPORATION

Estimated

Future Reserves

Attributable to the 100%

Leasehold Interests of the

Murphy Petrobras GOM JV

SEC Parameters

As of

December 31, 2023

/s/ Eric T. Nelson

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

[SEAL]

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

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

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January 17, 2024

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, 2023 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 13, 2024 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 Mexico 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. Murphy's net reserves attributable to Murphy's interests in non-MPGOM Gulf of Mexico and onshore U.S. properties are included in a separate report dated January 27, 2024. 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, 2023. Based on the estimates of total net proved reserves prepared by Murphy, the reserves audit conducted by Ryder Scott in this report addresses 10.8 percent of the total proved net reserves of Murphy on a barrel of oil equivalent, BOE basis as of December 31, 2023. At your 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, 2023 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, 2023, 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 as follows. The net reserves below represent 100 percent of the Murphy and Petrobras GOM JV (MPGOM) and include the non-controlling interest (NCI) 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, 2023

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves to MPGOM			
Oil/Condensate – Mbbl	59,547	12,522	72,069
Plant Products – Mbbl	2,502	543	3,045
Gas – MMcf	20,887	7,598	28,485
MBOE	65,530	14,331	79,861

SEC PARAMETERS
Estimated Net Reserves
Attributable to Murphy's Leasehold Interests in the
Murphy Petrobras GOM JV (MPGOM)
As of December 31, 2023

	Proved		
	Developed	Undeveloped	Total Proved
Net Reserves to MPGOM			
Oil/Condensate – Mbbl	47,874	10,181	58,055
Plant Products – Mbbl	2,017	443	2,460
Gas – MMcf	16,956	6,270	23,226
MBOE	52,717	11,669	64,386

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 6,234 MMcf at Murphy's Leasehold Interests of MPGOM, or 1.3 percent of the total MPGOM 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 November 2023, 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 2023. 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, 2023 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	$78.22/Bbl	$77.21/Bbl	$77.21/Bbl
	NGLs	WTI Cushing	$78.22/Bbl	$18.70/Bbl	$18.70/Bbl
	Gas	Henry Hub	$2.64/MMBTU	$2.30/Mcf	$2.94/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, 2023. 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, 2023, 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, 2023 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, 2023 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

/s/ Eric T. Nelson

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

[SEAL]

ETN (LPC)/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 2023 continuing education hours, Mr. Nelson attended over 20 hours of training during 2023 covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, 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 17 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

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

PREAMBLE

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

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

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

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

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.
Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

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

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

RESERVES (SEC DEFINITIONS)

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

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

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

PROVED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

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

and

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

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

DEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

Developed Producing (SPE-PRMS Definitions)

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

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

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

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

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

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

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

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

UNDEVELOPED RESERVES (SEC DEFINITIONS)

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

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

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

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

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

McDANIEL

January 25, 2024

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, 2023

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 Province of British Columbia and Alberta, 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 52.8 percent of its total company proved reserves on an equivalent barrel basis as of December 31, 2023, 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, 2023, for the same properties as those which we audited. The completion date of our report is January 15, 2024. 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, 2023. 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, and 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 2023 first-of-the month fiscal average pricing using benchmark pricing. Oil prices were based upon West Texas Intermediate at Cushing crude oil benchmark of USD$78.22 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$2.83 per Mcf of natural gas and CAD$108.28 per barrel of natural gas liquids. For total proved reserves in the Kaybob Duvernay Project, the estimated realized prices were CAD$3.16 per Mcf of natural gas, CAD$99.12 per barrel of oil and CAD$48.90 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, 2023
Certain Canadian Fields Audited by McDaniel & Associates

Business Unit	Crude Oil (Mbbl)	Natural Gas (Mboe)	Natural Gas Liquids (Mboe)	Oil Equivalent (Mboe)
Working Interest Reserves (after royalties)				
Proved Developed				
Kaybob Duvernay	6,042	3,664	1,384	11,090
Tupper Montney	-	171,835	393	172,228
Proved Undeveloped				
Kaybob Duvernay	7,030	3,193	1,214	11,437
Tupper Montney	-	195,529	345	195,874
Total Proved				
Kaybob Duvernay	13,072	6,857	2,598	22,527
Tupper Montney	-	367,364	738	368,102

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, 4,521 Mboe are attributed to fuel gas reserves in the Kaybob Duvernay and the Greater Tupper Montney Project.

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 65 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.

McDaniel & Associates Consultants Ltd. ("McDaniel") has been in the business of providing oil and gas reserves evaluations for over 65 years. Mr. Jared W. B. Wynveen, P. Eng., Executive Vice President has been with the firm since 2006, and has over 15 years of experience in the evaluation of oil and gas properties. As a senior engineer of McDaniel, Mr. Wynveen managed the preparation evaluation of the Murphy Oil Corporation's properties. Mr. Wynveen is a registered professionals with the Association of Professional Engineers and Geoscientist of Alberta (APEGA) with over 15 years of experience with the firm.

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 Jared Wynveen directly at (403) 218-1397.

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

/s/ Jared W. B. Wynveen

Jared W. B. Wynveen, P.Eng.
Executive Vice President
January 25, 2024

JWBW:jep
[23-0196]

CERTIFICATE OF QUALIFICATION

I, Jared W. B. Wynveen, 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 report entitled "Murphy Oil Corporation, Evaluation of the Canadian Oil and Gas Properties, As of December 31, 2023", dated January 25, 2024, 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 Mechanical Engineering, 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.

[SEAL]

APEGA ID 89207
Calgary, Alberta
Dated: January 25, 2024

Exhibit 99.4

Gaffney Cline

Proved Hydrocarbon Reserves Statement for Murphy Oil Corporation in Relation to the Oil/Gas Lac Da Vang Field, Vietnam as of December 31, 2023

Prepared for

Murphy Oil Corporation

January 26, 2024

Gaffney, Cline & Associates
(Consultants) Pte. Ltd.
150 Beach Road
#20-01/02 Gateway West
Singapore 189720

Tel: +65 6225 6951

UEN: 198701453N

January 26, 2024

Mr. Jeffrey Wilson
General Manager/Corporate Reserves
Murphy Oil Corporation
USA

Dear Mr. Wilson,

Proved Hydrocarbon Reserves Statement for Murphy Oil Corporation in Relation to the Oil/Gas Lac Da Vang Field, Vietnam as of December 31, 2023

This proved reserves statement has been prepared by Gaffney, Cline & Associates (Consultants) Pte Ltd ("GaffneyCline") and issued on January 26, 2024 at the request of Murphy Oil Corporation (Murphy or "the Client"), in respect of an oil and gas reserves audit of the Lac Da Vang ("LDV") Field in Vietnam where Murphy has a 40% operated participating interest. This report is intended for inclusion in Murphy's filings (10-K) with the United States Securities and Exchange Commission ("SEC").

The LDV Field is located in the south-east corner of Block 15-1/05 in the Cuu Long Basin on the continental shelf, offshore of southern Vietnam. It is about 120 km east-southeast of Vung Tau City. In the LDV area, the seawater depth ranges between 45 and 55 m. The location map is as shown in **Appendix I**.

GaffneyCline has conducted an independent audit examination as of December 31, 2023, of the hydrocarbon liquid and gas proved reserves of the LDV Field. On the basis of technical and other information made available to GaffneyCline concerning the field, we hereby provide the reserves statement in **Table 1**. Murphy's proved reserves summarized in the table is considered reasonable and compared to GaffneyCline's estimates are within the audit tolerance of not more than plus or minus 5 percent.

This report relates specifically and solely to the subject matter as defined in the scope of work in the Proposal for Services and is conditional upon the assumptions described herein. The report must be considered in its entirety and must only be used for the purpose for which it was intended.

GaffneyCline has been engaged to audit only the LDV Field as of December 31, 2023. As informed by Murphy, LDV Proved Reserves represent 1.7% of total Murphy's year-end 2023 Proved Reserves on a BOE basis.

The LDV gas is associated gas. The LDV gas is not reported in the LDV Field reserves as of December 31, 2023. The LDV gas sales agreement (GSA) with PetroVietnam/PetroVietnam Gas (PV/PVGas) is currently under discussion. Murphy plans to book the LDV gas reserves volumes only after the GSA is finalized.

Murphy provided documentation from March 2023 that shows the LDV gas sales process is progressing. PV/PVGas has accepted the receipt of LDV potential export gas through their pipeline system. Both Murphy and PV/PVGas are continuing to discuss tie-in options.

The gas will reach the market via the future trunkline. The trunkline CAPEX is part of the LDV oil field development CAPEX. Should the gas be monetized, gas will contribute only minor additional revenue to the LDV Field.

Table 1: Estimated Net Reserves
Murphy Oil Corporation for Oil/Gas Lac Da Vang Field, Block 15-1/05, Vietnam
as of December 31, 2023

Hydrocarbon	Oil (MMstb)	Gas (Bscf)	Total (MMboe)
Proved			
Developed	-	-	-
Undeveloped	12.1	2.8	12.6
Total Proved	**12.1**	**2.8**	**12.6**

Notes:
1. Murphy Net Reserves are Murphy's net economic entitlement volume after the deduction of royalties and profit share under the PSC that governs the asset (i.e., Company's share of cost oil/gas and profit oil/gas). The volumes shown above exclude the Government and partner share of production applicable under the PSC terms.
2. The above Reserves include production through to the end of the relevant PSC only and after considering the field economic limit.
3. Hydrocarbon liquid volumes represent crude oil estimated to be recovered during field separation and plant processing and are reported in millions of barrels at stock tank conditions (MMstb).
4. The above Gas Reserves represent only the volumes consumed in operations (CiO, or fuel). No gas reserves are reported related to the LDV gas sales since the gas sales agreement is still in negotiation with the buyer.

Reserves Assessment

GaffneyCline's audit of the Murphy reserves estimates was based on an independent review of the dynamic model and the underlying data such fluid laboratory tests and DST results and other pertinent information as provided by Murphy. The choice of a dynamic model to estimate production forecasts is appropriate for the LDV Field given that the field is undeveloped, the lack of direct analog fields and the complex interaction between matrix flow and fracture flow than cannot be captured with simpler models such as material balance. The underlying data set was comprehensive and questions were responded to in a timely and detailed manner by Murphy.

Particular scrutiny was paid to the history match of the model to the various DST's as the only available "production data" where the matching technique followed good industry practice and the resulting match parameters were geologically reasonable.

The proposed development plan covers 100% of reserves in this report and has been accurately implemented in the dynamic model and the resulting production forecasts yielded a range of oil recovery factors consistent with the expectation for the type of reservoir. The range of production forecasts from the dynamic model were considered to not fully capture the possible range of outcomes given the limited number of exploration and appraisal wells and tests and so the proved estimate has been based upon the lowest production forecast from the dynamic model.

This audit examination was based on reserves estimates and other information provided by Murphy to GaffneyCline from November to December 2023 and included such tests, procedures and adjustments as were considered necessary under the circumstances to prepare the report. All questions that arose during the course of the audit process were resolved to our satisfaction.

The economic tests for the December 31, 2023 Proved Reserves volumes were based on an expected realized crude price of US$85.41/bbl as advised by Murphy. This is after taking into account of the crude transportation cost of US$2.0/bbl. LDV crude is expected to be sold at US$4.00/bbl premium to Brent crude price of US$83.41/bbl. Crude from the Cuu Long Basin is historically traded at a premium to Brent. Brent crude price was based on the SEC requirement i.e., 12-month averages of the prices of the first day of the month preceding the estimates. The Brent crude price is found reasonable and aligned with the industry assumption.

Future capital costs were derived from development program forecasts prepared by Murphy for the LDV Field. Recent historical operating expense data were utilized as the basis for operating cost projections. GaffneyCline has found that Murphy has projected sufficient capital investments and operating expenses to produce economically the projected volumes.

It is GaffneyCline's opinion that the estimates of total remaining recoverable hydrocarbon liquid volumes at December 31, 2023, are, in the aggregate, reasonable and the reserves categorization is appropriate and consistent with the definitions for reserves set out in 17-CFR Part 210 Rule 4-10(a) of Regulation S-X of the United States Securities and Exchange Commission (as set out in **Appendix II**). GaffneyCline concludes that the methodologies employed by Murphy in the derivation of the volume estimates are appropriate and that the quality of the data relied upon, the depth and thoroughness of the estimation process are adequate.

Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Client, the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by, or at the direction of, the Client, and has accepted the accuracy and completeness of this data. GaffneyCline has no reason to believe that any material facts have been withheld but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas resources assessments must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas resources prepared by other parties may differ, perhaps materially, from those contained within this report.

The accuracy of any resources estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material.

Accordingly, resources estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

GaffneyCline's review and audit involved reviewing pertinent facts, interpretations and assumptions enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

Definition of 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.

Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status. All categories of reserves volumes quoted herein have been derived within the context of an economic limit test (ELT) assessment (pre-tax and exclusive of accumulated depreciation amounts).

GaffneyCline is not aware of any potential changes in regulations applicable to these fields that could affect the ability of the Client to produce the estimated reserves.

GaffneyCline is not aware of any carbon pricing impost that is applicable to the evaluation of the assets that are the subject of this report. GaffneyCline has also not included the impact of any potential carbon pricing scheme that may be implemented in the future.

GaffneyCline has not undertaken a site visit and inspection because it was not part of the scope of work. As such, GaffneyCline is not in a position to comment on the operations or facilities in place, their appropriateness and condition, or whether they are in compliance with the regulations pertaining to such operations. Further, GaffneyCline is not in a position to comment on any aspect of health, safety, or environment of such operation.

This report has been prepared based on GaffneyCline's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GaffneyCline is not in a position to attest to property title or rights, conditions of these rights (including GaffneyCline (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Qualifications

In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with the Client. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work. The technical qualifications of the person primarily responsible for the preparation of the reserves estimates presented in this report are given in **Appendix III**.

Notice

This report is intended for inclusion in its entirety in Murphy’s filings (10-K) with the United States Securities and Exchange Commission (SEC) in accordance with the disclosure requirements set forth in the SEC regulations. Murphy Oil Corporation will obtain GaffneyCline's prior written approval for any other use of any results, statements or opinions expressed to Murphy Oil Corporation in this report, which are attributed to GaffneyCline.

Yours sincerely,

Gaffney, Cline & Associates (Consultants) Pte Ltd

Project Manager

Doug Peacock, *Senior Director*

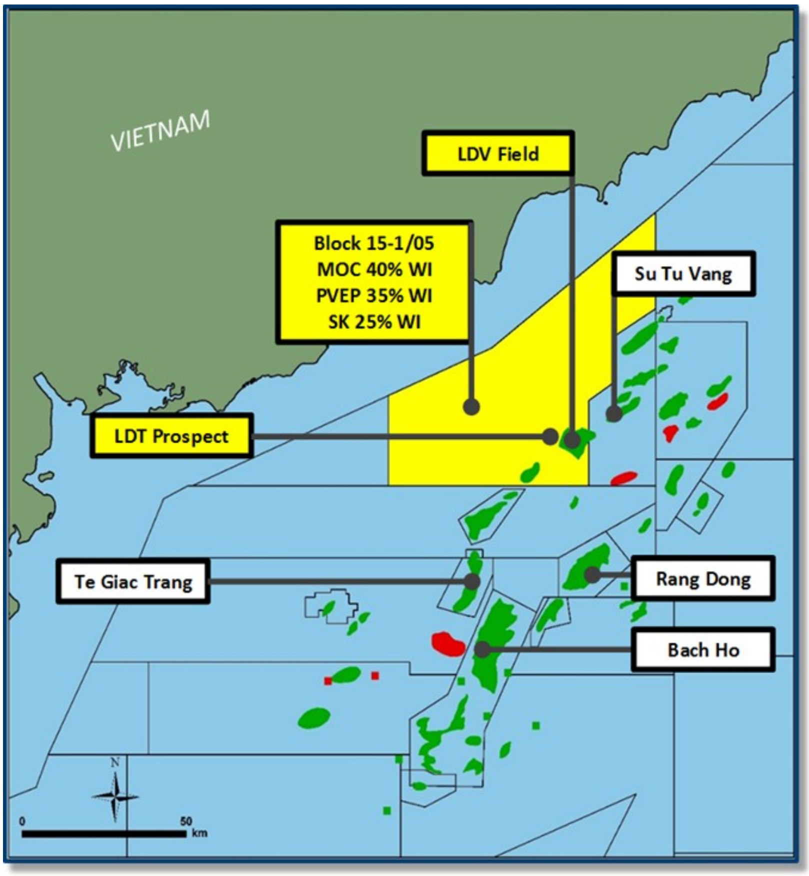
Appendices

Appendix I LDV Field Location Map
Appendix II SEC Reserves Definitions
Appendix III Statement of Qualifications
Appendix IV Glossary

Appendix I
LDV Field Location Map

Murphy Oil Corporation
January 26, 2024

Figure 1: LDV Field Location Map



Source: Murphy

Appendix II
SEC Reserves Definitions

Murphy Oil Corporation
January 26, 2024

U.S. SECURITIES AND EXCHANGE COMMISSION (SEC) MODERNIZATION OF OIL AND GAS REPORTING[1]

Oil and Gas Reserves Definitions and Reporting

(a) Definitions

(1) Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) 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.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) Bitumen. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non- hydrocarbons. 2

(4) Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) 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

[1] Extracted from 17 CFR Parts 210, 211, 229, and 249 [Release Nos. 33-8995; 34-59192; FR-78; File No. S7-15-08] RIN 3235- AK00].

(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.

(7) Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in pail as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

(15) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas- of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. 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.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities, they become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, arid fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves has been specifically attributed.

(22) 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.

(23) Proved properties. Properties with proved reserves.

(24) 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.

(25) 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.

(26) 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).

(27) 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.

(28) 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.

(29) Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) Unproved properties. Properties with no proved reserves.

Appendix III
Statement of Qualifications

Doug Peacock

Doug Peacock is a Senior Director with GaffneyCline and was the person primarily responsible for the preparation of the audit. Mr. Peacock has 40 years of diversified international industry experience mainly in geology and reserves estimates, including classification and reporting of reserves and resources. He is a recent member of the SPE's Oil & Gas Reserves Committee and routinely provides industry training courses on behalf of the SPE on the subject of reserves and resources assessment. He is a member of the Society of Petroleum Engineers (SPE) and holds a BSc degree in Geological Sciences from Leeds University, UK and a Master's Degree in Petroleum Geology from Imperial College, London.

Appendix IV
Glossary

Murphy Oil Corporation
January 26, 2024

GLOSSARY
List of Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment Expenditure
ACQ	Annual Contract Quantity
°API	Degrees API (American Petroleum Institute)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus Offset
A$	Australian Dollars
B	Billion (10^9)
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
BHA	Bottom Hole Assembly
BHC	Bottom Hole Compensated
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
bcpd	Barrels of condensate per day
BHP	Bottom Hole Pressure
blpd	Barrels of liquid per day
bpd	Barrels per day
BOE	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BOP	Blow Out Preventer
bopd	Barrels oil per day
bwpd	Barrels of water per day
BS&W	Bottom sediment and water
BTU	British Thermal Units
bwpd	Barrels water per day
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
cm	centimetres
CMM	Coal Mine Methane
CNG	Compressed Natural Gas
Cp	Centipoise (a measure of viscosity)
CSG	Coal Seam Gas
CT	Corporation Tax
DCQ	Daily Contract Quantity
Deg C	Degrees Celsius
Deg F	Degrees Fahrenheit
DHI	Direct Hydrocarbon Indicator
DST	Drill Stem Test
DWT	Dead-weight ton
E&A	Exploration & Appraisal

E&P	Exploration and Production
EBIT	Earnings before Interest and Tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement Interest
EIA	Environmental Impact Assessment
EMV	Expected Monetary Value
EOR	Enhanced Oil Recovery
EUR	Estimated Ultimate Recovery
FDP	Field Development Plan
FEED	Front End Engineering and Design
FPSO	Floating Production, Storage and Offloading
FSO	Floating Storage and Offloading
ft	Foot/feet
Fx	Foreign Exchange Rate
g	gram
g/cc	grams per cubic centimetre
gal	gallon
gal/d	gallons per day
G&A	General and Administrative costs
GBP	Pounds Sterling
GDT	Gas Down to
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOR	Gas Oil Ratio
GTL	Gas to Liquids
GWC	Gas water contact
HDT	Hydrocarbons Down to
HSE	Health, Safety and Environment
HSFO	High Sulphur Fuel Oil
HUT	Hydrocarbons up to
H_2S	Hydrogen Sulphide
IOR	Improved Oil Recovery
IPP	Independent Power Producer
IRR	Internal Rate of Return
J	Joule (Metric measurement of energy) I kilojoule = 0.9478 BTU)
k	Permeability
KB	Kelly Bushing
KJ	Kilojoules (one Thousand Joules)
kl	Kilolitres
km	Kilometres
km^2	Square kilometres
kPa	Thousands of Pascals (measurement of pressure)
KW	Kilowatt
KWh	Kilowatt hour
LKG	Lowest Known Gas
LKH	Lowest Known Hydrocarbons

LKO	Lowest Known Oil
LNG	Liquefied Natural Gas
LoF	Life of Field
LPG	Liquefied Petroleum Gas
LTI	Lost Time Injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MCM	Management Committee Meeting
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
mD	Measure of Permeability in millidarcies
MD	Measured Depth
MDT	Modular Dynamic Tester
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
MFT	Multi Formation Tester
mg/l	milligrams per litre
MJ	Megajoules (One Million Joules)
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mode	Value that exists most frequently in a set of values = most likely
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring While Drilling
MWh	Megawatt hour
mya	Million years ago
NGL	Natural Gas Liquids
N_2	Nitrogen
NPV	Net Present Value
OBM	Oil Based Mud
OCM	Operating Committee Meeting
ODT	Oil down to
OPEX	Operating Expenditure
OWC	Oil Water Contact
p.a.	Per annum
Pa	Pascals (metric measurement of pressure)
P&A	Plugged and Abandoned
PDP	Proved Developed Producing
PI	Productivity Index

PJ	Petajoules (10^{15} Joules)
PSDM	Post Stack Depth Migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved Undeveloped
PVT	Pressure volume temperature
P10	10% Probability
P50	50% Probability
P90	90% Probability
Rf	Recovery factor
RFT	Repeat Formation Tester
RT	Rotary Table
RTA	Rate Transient Analysis
R_w	Resistivity of water
SCAL	Special core analysis
cf or scf	Standard Cubic Feet
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
s_o	Oil Saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
s_w	Water Saturation
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical Committee Meeting
TOC	Total Organic Carbon
TOP	Take or Pay
Tpd	Tonnes per day
TVD	True Vertical Depth
TVDss	True Vertical Depth Subsea
USGS	United States Geological Survey
US$	United States Dollar
VSP	Vertical Seismic Profiling
WC	Water Cut
WI	Working Interest
WPC	World Petroleum Council
WTI	West Texas Intermediate

wt%	Weight percent
1H05	First half (6 months) of 2005 (example of date)
2Q06	Second quarter (3 months) of 2006 (example of date)
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
%	Percentage