Cautionary Statement

Cautionary Note to US Investors – The United States Securities and Exchange Commission (SEC) requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We may use certain terms in this presentation, such as “resource”, “gross resource”, “recoverable resource”, “net risked PMEAN resource”, “recoverable oil”, “resource base”, “EUR” or “estimated ultimate recovery” and similar terms that the SEC’s rules prohibit us from including in filings with the SEC. The SEC permits the optional disclosure of probable and possible reserves in our filings with the SEC. Investors are urged to consider closely the disclosures and risk factors in our most recent Annual Report on Form 10-K filed with the SEC and any subsequent Quarterly Report on Form 10-Q or Current Report on Form 8-K that we file, available from the SEC’s website.

This presentation 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 “Risk Factors” in our most recent Annual Report on Form 10-K filed with the U.S. Securities and Exchange Commission (“SEC”) and any subsequent Quarterly Report on Form 10-Q or Current Report on Form 8-K that we file, available from the SEC’s website and from Murphy Oil Corporation’s website at http://ir.murphyoilcorp.com. 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 presentation. Murphy Oil Corporation undertakes no duty to publicly update or revise any forward-looking statements.

Non-GAAP Financial Measures – This presentation refers to certain forward-looking non-GAAP measures. Definitions of these measures are included in the appendix.
Advancing Strategic Priorities

DELEVER

- Utilized proceeds from non-core divestiture to progress capital allocation framework in FY 2023
- Achieved FY 2023 debt reduction goal of ~$500 MM through senior notes redemption and partial tender
- Advanced Murphy 2.0 of capital allocation framework with $1.7 BN of total debt reduction since year-end 2020

EXECUTE

- Produced 186 MBOEPD with 98 MBOPD, or 52 percent, oil volumes in FY 2023
- Initiated procurement for Lac Da Vang field development project in Vietnam with first oil forecast in 2026
- Resumed production at the non-operated Terra Nova field in 4Q 2023
- Acquired 8 percent working interest in the non-operated Zephyrus discovery in the Gulf of Mexico for $13 MM after closing adjustments in 4Q 2023
- Achieved 139% total reserve replacement with 724 MMBOE preliminary proved reserves and ~11-year reserve life

EXPLORE

- Named apparent high bidder on 8 exploration blocks in Gulf of Mexico Federal Lease Sale 261 in 4Q 2023
- Preparing for 2024 exploration program in Gulf of Mexico and Vietnam
- Advancing seismic reprocessing projects for Gulf of Mexico and Côte d'Ivoire

RETURN

- Repurchased $150 MM, or 3.4 MM shares, at an average price of $43.96 / share in FY 2023
- $450 MM remaining under share repurchase authorization as of Dec 31, 2023
- Announced 9% dividend increase of quarterly cash dividend to $1.20 / share annualized in 1Q 2024

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Murphy 2.0 is when long-term debt equals $1.0 BN – $1.8 BN. During this time, ~75% of adjusted free cash flow is allocated to debt reduction and the remaining ~25% is distributed through share buybacks and potential dividend increases. Adjusted FCF is defined as cash flow from operations before working capital change, less capital expenditures, distributions to NCI and projected payments, quarterly dividend and accretive acquisitions.

www.murphyoilcorp.com
NYSE: MUR
Production, Pricing and Revenue
Generating High Revenue From Oil Production

4Q 2023 Production 185 MBOEPD, 94 MBOPD
• 51% oil, 6% NGLs, 43% natural gas

FY 2023 Production 186 MBOEPD, 98 MBOPD
• 52% oil, 6% NGLs, 42% natural gas

4Q 2023 Pricing
• $79.27 / BBL realized oil price
• $20.83 / BBL realized natural gas liquids price
• $2.12 / MCF realized natural gas price

FY 2023 $3.2 BN Revenue

Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated.
Prices are shown excluding hedges and before transportation, gathering, processing. Revenue is from production only and excludes sales from purchased gas.
2023 Proved Reserves
Maintaining Proved Reserves and Reserve Life

- Total proved reserves 724 MMBOE at YE 2023 vs 697 MMBOE at YE 2022
  - Achieved 139% total reserve replacement
- Added ~13 MMBOE of proved reserves for Lac Da Vang field in Vietnam
- Maintained proved reserves from FY 2020 – FY 2023 with average annual CAPEX of ~$1.07 BN, excluding NCI and including acquisitions
- 57% proved developed reserves with 41% liquids-weighting
- Proved reserve life ~11 years

Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated
Reserves are based on preliminary SEC year-end 2023 audited proved reserves and exclude noncontrolling interest
Financial Results
Generating Income to Support Corporate Priorities

4Q 2023 Financial Results
• Net income $116 MM; adjusted net income $140 MM
• EBITDA $375 MM; adjusted EBITDA $414 MM

4Q 2023 Significant Other Impacts
• Accrued CAPEX of $219 MM
  • Excludes $13 MM of NCI CAPEX and $20 MM of acquisition-related CAPEX
• Repurchased $75 MM of common stock at an average price of $43.42 / share

FY 2023 Significant Other Impacts
• Accrued CAPEX of $1.0 BN
  • Excludes $70 MM of NCI CAPEX and $60 MM of acquisition-related CAPEX
    • $33 MM related to Cote d’Ivoire, $14 MM related to Vietnam and $13 MM for non-operated Zephyrus working interest

<table>
<thead>
<tr>
<th>Net Income Attributable to Murphy ($MM Except Per Share)</th>
<th>4Q 2023</th>
<th>FY 2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income (loss)</td>
<td>$116</td>
<td>$662</td>
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<tr>
<td>$/Diluted share</td>
<td>$0.75</td>
<td>$4.22</td>
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<table>
<thead>
<tr>
<th>Adjusted Income from Continuing Ops.</th>
<th>4Q 2023</th>
<th>FY 2023</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted income (loss)</td>
<td>$140</td>
<td>$709</td>
</tr>
<tr>
<td>$/Diluted share</td>
<td>$0.90</td>
<td>$4.52</td>
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</table>

<table>
<thead>
<tr>
<th>Adj. EBITDA Attributable to Murphy ($MM)</th>
<th>4Q 2023</th>
<th>FY 2023</th>
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</thead>
<tbody>
<tr>
<td>EBITDA attributable to Murphy</td>
<td>$375</td>
<td>$1,807</td>
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<tr>
<td>Accretion of asset retirement obligations</td>
<td>$11</td>
<td>$41</td>
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<tr>
<td>Foreign exchange loss and other</td>
<td>$28</td>
<td>$53</td>
</tr>
<tr>
<td>Adjusted EBITDA</td>
<td>$414</td>
<td>$1,901</td>
</tr>
</tbody>
</table>

Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated.
Financial Results
Strengthening Balance Sheet

Solid Foundation to Withstand Commodity Price Cycles
- $1.1 BN of liquidity on Dec 31, 2023
  - Includes $800 MM senior unsecured credit facility due Nov 2027
- Achieved FY 2023 debt reduction goal of ~$500 MM through senior notes redemption and partial tender
- Reduced annual long-term debt interest expense $84 MM since year-end 2020

De-Risking Balance Sheet While Enhancing Dividend
- Increased quarterly dividend 9% in 1Q 2024 to $1.20 / share annualized, restoring to 2016 level
- ~64% decrease in net debt since YE 2016

Long-Term Debt Profile
- Total senior notes outstanding: $1.3 BN
- Weighted avg fixed coupon: 6.2%
- Weighted avg maturity: 8.1 years
  - Next maturity Dec 2027
Capital Allocation Priorities
Reducing Long-Term Debt, Increasing Shareholder Returns Beyond Quarterly Dividend With Framework\(^1\)

**Murphy 1.0** – Long-Term Debt > $1.8 BN
- Allocate adjusted FCF to long-term debt reduction
- Continue supporting the quarterly dividend

**Murphy 2.0** – Long-Term Debt of $1.0 BN – $1.8 BN
- \(\sim 75\%\) of adjusted FCF allocated to debt reduction
- \(\sim 25\%\) distributed through share buybacks and potential dividend increases

**Murphy 3.0** – Long-Term Debt \(\leq\) $1.0 BN
- Up to 50% of adjusted FCF allocated to the balance sheet
- Minimum of 50% of adjusted FCF allocated to share buybacks and potential dividend increases

---

**Adjusted Free Cash Flow Formula**

\[
\text{Adjusted Free Cash Flow (Adjusted FCF)} = \text{Cash Flow From Operations Before WC Change} - \text{Capital expenditures} - \text{Distributions to NCI and projected payments}^3 - \text{Quarterly dividend} - \text{Accretive acquisitions}
\]

---

**Remaining Share Repurchase Program\(^2\)**
- Authorized by Board
- \$450 MM

---

\(^1\) The timing and magnitude of debt reductions and share repurchases will largely depend on oil and natural gas prices, development costs and operating expenses, as well as any high-return investment opportunities. Because of the uncertainties around these matters, it is not possible to forecast how and when the company’s targets might be achieved.

\(^2\) The share repurchase program allows the company to repurchase shares through a variety of methods, including but not limited to open market purchases, privately negotiated transactions and other means in accordance with federal securities laws, such as through Rule 10b5-1 trading plans and under Rule 10b-18 of the Exchange Act. 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.

\(^3\) Other projected payments such as the contractual contingent payments projected to end after the second quarter of 2023.
CONTINUED ENVIRONMENTAL STEWARDSHIP

ADVANCING OUR CLIMATE GOALS

- GHG
  - 15-20% REDUCTION IN GHG EMISSIONS INTENSITY by 2030 compared to 2019

- CO2
  - LOWEST EMISSIONS INTENSITIES since 2013

- ZERO routine flaring by 2030

- HIGHEST WATER RECYCLING RATIO in company history

POSITIVELY IMPACTING OUR PEOPLE AND COMMUNITIES

CONSISTENTLY OUTPERFORMING

US Bureau of Labor Statistics for industry TRIR and LTIR

BEST PLACE FOR WORKING PARENTS

by the Greater Houston Partnership in 2022 – 2024

MOST RESPONSIBLE COMPANIES

by Newsweek in 2024

- more than 3,200 students received El Dorado Promise scholarships since 2007

STRONG GOVERNANCE OVERSIGHT

Well-defined BOARD AND MANAGERIAL OVERSIGHT

and management of ESG matters

third consecutive year of THIRD-PARTY ASSURANCE

of GHG Scope 1 and 2 data

GHG INTENSITY GOAL IN ANNUAL INCENTIVE PLAN

added in 2021

20% ESG METRIC WEIGHTING IN ANNUAL INCENTIVE PLAN

Emissions, TRIR and IOGP spill rate
4Q 2023 Onshore Update
Consistent Production from Multi-Decade Inventory

4Q 2023 Total Onshore Production 100 MBOEPD, 30% Liquids

- Eagle Ford Shale 31 MBOEPD, 86% liquids
  - 3 non-operated Tilden wells online as planned
- Tupper Montney 386 MMCFD net
  - Initiated drilling 10-well pad with 2 rigs
- Kaybob Duvernay 4 MBOEPD, 69% liquids

Photo courtesy of Patterson-UTI Drilling Company LLC
4Q 2023 Offshore Update
Oil-Weighted Offshore Assets Generate High-Margin Barrels

4Q 2023 Total Production 84 MBOEPD, 82% Oil

- Gulf of Mexico 81 MBOEPD, 81% oil
  - Brought online operated Dalmatian #1 (DeSoto Canyon 90) well in 4Q 2023
  - Drilled and completed operated Marmalard #3 (Mississippi Canyon 255) well in 4Q 2023, online 1Q 2024
  - Acquired 8% working interest in non-operated Zephyrus discovery for $13 MM after closing adjustments
- Offshore Canada 4 MBOEPD, 100% oil
  - Resumed production at non-operated Terra Nova FPSO in 4Q 2023, wells ramping through 1Q 2024
Initiated Côte d’Ivoire Exploration Area

- Signed PSCs on 5 exploration blocks in 2Q 2023
  - Commenced seismic reprocessing
- One block includes undeveloped Paon discovery
  - Committed to submitting field development plan by YE 2025

Vietnam

- Preparing to drill 2 exploration wells in FY 2024
- Adds upside to Lac Da Vang field development project sanctioned in 4Q 2023

Gulf of Mexico Federal Lease Sale 261

- Dec 20, 2023
- Apparent high bidder on 8 exploration blocks
2024 Capital Plan
Prioritizing Capital To Maximize Production and Adjusted Free Cash Flow\(^1\)

**Further Delevering, Enhancing Shareholder Returns**

- FY 2024 guidance $920 MM – $1.02 BN CAPEX
- ~60% of spend is in 1H 2024
- ~85% of capital is for development
  - 80% of development capital is operated

**Targeting Murphy 3.0 in 2024**

- $300 MM debt reduction goal in 2024\(^2\)
- Increased dividend in 1Q 2024 to $1.20 / share annualized
- Share repurchases to equal 25% of adjusted FCF\(^1\) until goal reached

---

1. Adjusted FCF is defined as cash flow from operations before working capital change, less capital expenditures, distributions to NCI and projected payments, quarterly dividend and accretive acquisitions
2. Assumes $75 WTI oil price in FY 2024
2024 Production Plan

1Q 2024 Production Guidance 163 – 171 MBOEPD
• 89 MBOPD or 53% oil, 59% liquids volumes
• Includes planned downtime of:
  • 13 MBOEPD of total Gulf of Mexico downtime, comprised of:
    • 6 MBOEPD for workovers; will return to production 1H 2024
    • 5 MBOEPD for planned facility and downstream maintenance
    • 2 MBOEPD for subsea equipment repair in Mormont field
  • 2 MBOEPD of onshore downtime
• No onshore wells brought online since 3Q 2023

FY 2024 Production Guidance 180 – 188 MBOEPD
• 96 MBOPD or 52% oil, 58% liquids volumes

Quarterly Production Trends MBOEPD

FY 2024E Production
By Area

FY 2024E Production by Product
Eagle Ford Shale
Enhancing Portfolio and Production Through Strong Execution, Improved Completions

$320 MM 2024 Capital Budget, ~30 MBOEPD
- 71% oil volumes, 86% liquids volumes
- 19 operated wells online – 15 Catarina wells, 4 Karnes wells
- 18 gross non-operated Tilden wells online
- 11 operated Karnes wells drilled for early 2025 completion

Strong Performance Across Locations
- Optimized completions design continues to outperform expectations
- Utilizing new, high-tech drilling rig with industry-leading capabilities
  - Adaptive auto-drilling and process automation
  - Low carbon solution with dual fuel and 100% natural gas capability

Eagle Ford Shale Acreage

FY 2024E Wells Online

Note: Non-op well cadence subject to change per operator plans
Eagle Ford Shale non-operated wells adjusted for 41% average working interest
Tupper Montney
New Completions Design Drives Strong Well Performance

$90 MM 2024 Capital Budget, ~370 MMCFD
- 100% dry gas
- 13 operated wells online in 2Q 2024
- Assumes C$2.46 / MMBTU AECO

New Completions Design Enhancing Well Performance
- Producing 2 of top 10, and 4 of top 15, natural gas wells in Canada\textsuperscript{1}
- Achieving some of highest IP30 rates in company history
- Optimizing fracs in real-time

1 BOE Report dated August 31, 2023
Acreage as of January 23, 2024
Kaybob Duvernay
Future Oil-Weighted Optionality Preserved

$40 MM 2024 Capital Budget, ~4 MBOEPD
• 55% oil volumes, 67% liquids volumes
• 3 operated wells online in 2Q 2024

Robust Remaining Well Inventory
• 488 future locations on ~110,000 net acres
• Maintaining base production through optimization initiatives
• Minimal infrastructure required to increase production
2024 Offshore Plan
Focusing on Executing Highly-Accretive Development Projects

2024 Offshore Capital Budget $370 MM

88 MBOEPD Forecast for FY 2024

$300 MM for Gulf of Mexico, ~79 MBOEPD
  • 80% oil volumes
  • Primarily for operated and non-operated subsea tiebacks
  • Marmalard (Mississippi Canyon 255) #3 well online 1Q 2024

$45 MM for Other Offshore Development
  • $40 MM for Lac Da Vang field development in Vietnam
  • $5 MM for Paon field development plan in Côte d’Ivoire

$25 MM for Offshore Canada, ~9 MBOEPD
  • 100% oil volumes
  • Primarily for non-op Hibernia development drilling

Highly-Accretive Development and Tieback Projects

<table>
<thead>
<tr>
<th>Field</th>
<th>Drilling</th>
<th>Completions</th>
<th>Online</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marmalard</td>
<td>✔</td>
<td>✔</td>
<td>1Q 2024</td>
</tr>
<tr>
<td>Khaleesi</td>
<td></td>
<td></td>
<td>2Q 2024</td>
</tr>
<tr>
<td>Mormont</td>
<td></td>
<td>✔</td>
<td>3-4Q 2024</td>
</tr>
<tr>
<td>Samurai</td>
<td></td>
<td></td>
<td>2025</td>
</tr>
<tr>
<td>Dalmatian</td>
<td></td>
<td></td>
<td>2025</td>
</tr>
<tr>
<td>Longclaw</td>
<td>✔</td>
<td>✔</td>
<td>2026</td>
</tr>
<tr>
<td>St. Malo (non-op)</td>
<td>✔</td>
<td>✔</td>
<td>1Q 2024</td>
</tr>
<tr>
<td>Lucius (non-op)</td>
<td>✔</td>
<td>✔</td>
<td>1H 2024-2025</td>
</tr>
</tbody>
</table>

Offshore Canada Development Projects

<table>
<thead>
<tr>
<th>Field</th>
<th>Activity</th>
<th>Online</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hibernia (non-op)</td>
<td>5 development wells</td>
<td>2024</td>
</tr>
</tbody>
</table>

Planned well | Drilling in progress | Drilled well
# 2024 Offshore Workover Projects

## Execution Update

### Well Workover Projects

- Non-op Lucius #9 well workover completed in 4Q 2023, online 1Q 2024
- Operated Marmalard #1 and #2 zone changes scheduled for 1Q 2024
  - $8 MM net workover expense
- Operated Neidermeyer #1 well workover scheduled for 1Q 2024, online 2Q 2024
  - $31 MM net workover expense
- Operated Dalmatian #2 subsurface safety valve repair scheduled for mid-2024
  - $29 MM net workover expense
- Non-op Kodiak #3 well workover scheduled for mid-2024
  - $13 MM net workover expense

### Operated Workovers and Projects

<table>
<thead>
<tr>
<th>Field</th>
<th>Location</th>
<th>Project</th>
<th>Online</th>
<th>Net Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marmalard</td>
<td>Mississippi Canyon 255</td>
<td>Zone changes</td>
<td>1Q 2024</td>
<td>~1.5 MBOEPD</td>
</tr>
<tr>
<td>Mormont</td>
<td>Mississippi Canyon 478</td>
<td>Subsea equipment repair</td>
<td>1Q 2024</td>
<td>~5 MBOEPD</td>
</tr>
<tr>
<td>Neidermeyer</td>
<td>Mississippi Canyon 208</td>
<td>Workover</td>
<td>2Q 2024</td>
<td>~4.0 MBOEPD</td>
</tr>
<tr>
<td>Dalmatian</td>
<td>DeSoto Canyon 4</td>
<td>Subsurface safety valve repair</td>
<td>Mid-2024</td>
<td>~1.5 MBOEPD</td>
</tr>
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### Non-Operated Workovers and Projects

<table>
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<tr>
<th>Field</th>
<th>Location</th>
<th>Project</th>
<th>Online</th>
<th>Net Production</th>
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<tr>
<td>Lucius</td>
<td>Keathley Canyon 919</td>
<td>Workover</td>
<td>1Q 2024</td>
<td>~1.0 MBOEPD</td>
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<tr>
<td>Kodiak</td>
<td>Mississippi Canyon 727</td>
<td>Stimulation / zone addition</td>
<td>Mid-2024</td>
<td>~1.0 MBOEPD incremental</td>
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</table>
Lac Da Vang Field Development Project
Cuu Long Basin, Vietnam

Lac Da Vang Field Development Overview

- Murphy 40% (Op), PetroVietnam Exploration Production 35%, SK Earthon 25%
- 100 MMBOE estimated gross recoverable resource
  - 13 MMBOE of preliminary net proved reserves added at year-end 2023
- Estimated 10 – 15 MBOEPD net peak production
- Progressing award of major contracts
- Targeting first oil in FY 2026, development through FY 2029
  - $40 MM capital plan for FY 2024

Acreage as of January 23, 2024
Reserves are based on preliminary SEC year-end 2023 audited proved reserves
2024 Exploration Plan

$120 MM 2024 Total Exploration Capital Budget

• Targeting ~120 MMBOE net mean unrisked resources with FY 2024 program
• Drilling 2 Gulf of Mexico and 2 Vietnam wells

Gulf of Mexico Exploration Plan

• Prospects near existing infrastructure
• Ocotillo (Mississippi Canyon 40)
  • Oxy 33% (Op), Murphy 33%, Chevron 33%
  • Targeting spud 2Q 2024
• Orange (Mississippi Canyon 216)
  • Oxy 50% (Op), Murphy 50%
  • Targeting spud 2Q 2024

Acreage as of January 23, 2024
Exploration Update
Cuu Long Basin, Vietnam

Asset Overview

• Murphy 40% (Op), PetroVietnam Exploration Production 35%, SK Earthon 25%

Block 15-1/05

• Advancing plans for Lac Da Hong exploration well
  • Targeting spud 4Q 2024
  • Mean to upward gross resource potential
    • 65 MMBOE – 135 MMBOE

Block 15-2/17

• Advancing plans for Hai Su Vang exploration well
  • Targeting spud 3Q 2024
  • Mean to upward gross resource potential
    • 170 MMBOE – 430 MMBOE

Acreage as of January 23, 2024
Development and Exploration Update
Tano Basin, Côte d’Ivoire

Asset Overview

• ~1.5 MM gross acres, equivalent to 256 Gulf of Mexico blocks
• Initiated seismic reprocessing
• Adjacent to oil discoveries, including Baleine
• Identified diverse opportunity set across various exploration play types

Blocks CI-102, CI-502, CI-531 and CI-709

• Murphy 90% (Op), PETROCI\textsuperscript{1} 10%

Block CI-103

• Murphy 85% (Op), PETROCI\textsuperscript{1} 15%

Includes Undeveloped Paon Discovery

• Commitment to submit viable field development plan by YE 2025
• Reviewing commerciality and field development concepts

Acreage as of January 23, 2024
1 Société Nationale d’Opérations Pétrolières de la Côte d’Ivoire
LOOKING AHEAD
Peer-Leading Balance Sheet and Free Cash Flow Metrics

Peer-Leading Cash Flow Yield

Financial Strength Provides Low Risk to Sustainable Returns

- Peer leading ~$23 FCF / BOE
- 0.7x debt / TTM EBITDA

Plan Reflects Metrics That Support Additional Cash Return Growth

- 2024 plan achieves $1.0 BN debt target
- Murphy 3.0 of capital allocation framework provides > 50% payout of adjusted FCF¹

¹ Adjusted FCF is defined as cash flow from operations before working capital change, less capital expenditures, distributions to NCI and projected payments, quarterly dividend and accretive acquisitions

² Source: Internal estimates and Bloomberg as of 3Q 2023

Peers include APA, CIVI, CNX, CPE, CTRA, DVN, HES, KOS, MRO, MTDR, OVV, RRC, SM, SWN, TALO

Free Cash Flow Yield – TTM² By Percentage

Free Cash Flow / Production² $ / BOE

Debt-to-EBITDA – TTM²
Disciplined Strategy Leads to Long-Term Value With Current Assets

**NEAR-TERM**
- Reducing debt by $300 MM to reach $1.0 BN debt target in 2024 with no debt maturities until Dec 2027
- Reinvesting ~50% of operating cash flow to maintain average 53% oil-weighting near-term to enhance oil production long-term
- Delivering average production of ~195 MBOEPD with CAGR of 5%
- Maintaining offshore production average of ~95 MBOEPD
- Spending annual average CAPEX of ~$1.1 BN
- Targeting enhanced payouts to shareholders through dividend increases and share buybacks while deleveraging
- Targeting first oil in Vietnam in 2026
- Drilling high-impact exploration wells in Gulf of Mexico, Vietnam and Côte d'Ivoire and conducting additional geophysical studies

2024 | 2025 | 2026

**LONG-TERM**
- Realizing average annual production of 210-220 MBOEPD with > 50% average oil weighting
- Reinvesting ~45% of operating cash flow
- Allocating capital to high-returning investment opportunities for further growth in 2028+
- Exploration portfolio provides upside to plan
- Ample free cash flow funds further debt reductions, continuing cash returns to shareholders and accretive investments
- Achieving metrics that are consistent with an investment grade rating

2027 | 2028

---

1 Assumes $75 WTI oil price, $3.50 HH natural gas price in FY 2024 and no exploration success
Consistent Focus for Future Success

2023

- Protected our employees and the environment
- Achieved lowest carbon intensity on record
- Executed capital allocation framework
- Continued improving balance sheet with decade-low net debt
- Increased proved reserves
- Sanctioned development project in Vietnam with exploration upside
- Entered new exploration area in Côte d’Ivoire

2024 and Beyond

- Enduring focus on stakeholder protection and further emission improvements
- Continuing focus on shareholder returns
- Increasing quarterly dividend
- Enhancing balance sheet for financial resilience
- Maintaining large inventory of multi-basin, oil-weighted assets
- Expanding long-term exploration portfolio
2023 FOURTH QUARTER EARNINGS
CONFERENCE CALL & WEBCAST
JANUARY 25, 2024

ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER
Non-GAAP Financial Measure Definitions and Reconciliations

The following list of Non-GAAP financial measure definitions and related reconciliations is intended to satisfy the requirements of Regulation G of the Securities Exchange Act of 1934, as amended. This information is historical in nature. Murphy undertakes no obligation to publicly update or revise any Non-GAAP financial measure definitions and related reconciliations.
Non-GAAP Reconciliation

**ADJUSTED EARNINGS**

Murphy defines Adjusted Earnings as net income attributable to Murphy\(^1\) adjusted to exclude discontinued operations and certain other items that affect comparability between periods.

Adjusted Earnings is used by management to evaluate the company’s operational performance and trends between periods and relative to its industry competitors.

Adjusted Earnings, as reported by Murphy, may not be comparable to similarly titled measures used by other companies and it should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). Adjusted Earnings has certain limitations regarding financial assessments because it excludes certain items that affect net income. Adjusted Earnings should not be considered in isolation or as a substitute for an analysis of Murphy’s GAAP results as reported.

---

### (Millions of dollars, except per share amounts)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income attributable to Murphy (GAAP)(^1)</td>
<td>116.3</td>
<td>199.4</td>
</tr>
<tr>
<td>Discontinued operations loss</td>
<td>0.7</td>
<td>0.2</td>
</tr>
<tr>
<td>Net income from continuing operations attributable to Murphy</td>
<td>117.0</td>
<td>199.6</td>
</tr>
<tr>
<td>Adjustments(^2):</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Write-off of previously suspended exploration well</td>
<td>-</td>
<td>22.7</td>
</tr>
<tr>
<td>Asset retirement obligation losses</td>
<td>16.9</td>
<td>30.8</td>
</tr>
<tr>
<td>Foreign exchange loss (gain)</td>
<td>11.1</td>
<td>5.7</td>
</tr>
<tr>
<td>Mark-to-market (gain) on contingent consideration</td>
<td>-</td>
<td>(20.2)</td>
</tr>
<tr>
<td>Mark-to-market (gain) on derivative instruments</td>
<td>-</td>
<td>(76.0)</td>
</tr>
<tr>
<td>Loss (gain) on sale of assets</td>
<td>-</td>
<td>0.7</td>
</tr>
<tr>
<td>Early redemption of debt cost</td>
<td>-</td>
<td>3.5</td>
</tr>
<tr>
<td>Total adjustments, before taxes</td>
<td>28.0</td>
<td>(32.8)</td>
</tr>
<tr>
<td>Income tax expense (benefit) related to adjustments</td>
<td>(5.0)</td>
<td>6.5</td>
</tr>
<tr>
<td>Total adjustments after taxes</td>
<td>23.0</td>
<td>(26.3)</td>
</tr>
<tr>
<td>Adjusted net income from continuing operations attributable to Murphy (Non-GAAP)</td>
<td>140.0</td>
<td>173.3</td>
</tr>
<tr>
<td>Adjusted net income from continuing operations per average diluted share (Non-GAAP)</td>
<td>0.90</td>
<td>1.10</td>
</tr>
</tbody>
</table>

\(^1\) ‘Attributable to Murphy’ represents the economic interest of Murphy excluding noncontrolling interest in MP GOM

\(^2\) Certain prior-period amounts have been updated to conform to the current period presentation
Non-GAAP Reconciliation

EBITDA and EBITDAX

Murphy defines EBITDA as net income (loss) attributable to Murphy¹ before interest, taxes, depreciation, depletion and amortization (DD&A). Murphy defines EBITDAX as net income (loss) attributable to Murphy before interest, taxes, DD&A and exploration expense.

Management believes that EBITDA and EBITDAX provide useful information for assessing Murphy's financial condition and results of operations and are widely accepted financial indicators of the ability of a company to incur and service debt, fund capital expenditure programs, pay dividends and make other distributions to stockholders.

EBITDA and EBITDAX, as reported by Murphy, may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). EBITDA and EBITDAX have certain limitations regarding financial assessments because they exclude certain items that affect net income and net cash provided by operating activities. EBITDA and EBITDAX should not be considered in isolation or as a substitute for an analysis of Murphy’s GAAP results as reported.

<table>
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<tr>
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<th></th>
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<tr>
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</tr>
<tr>
<td>Income tax expense</td>
<td>29.1</td>
<td>61.9</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>23.7</td>
<td>34.7</td>
</tr>
<tr>
<td>Depreciation, depletion and amortization expense²</td>
<td>206.0</td>
<td>195.7</td>
</tr>
<tr>
<td>EBITDA attributable to Murphy (Non-GAAP)</td>
<td>375.1</td>
<td>491.7</td>
</tr>
<tr>
<td>Exploration expenses²</td>
<td>82.0</td>
<td>61.0</td>
</tr>
<tr>
<td>EBITDAX attributable to Murphy (Non-GAAP)</td>
<td>457.1</td>
<td>552.7</td>
</tr>
</tbody>
</table>

¹ ‘Attributable to Murphy’ represents the economic interest of Murphy excluding noncontrolling interest in MP GOM
² Depreciation, depletion, and amortization expense and exploration expenses used in the computation of EBITDA and EBITDAX exclude the portion attributable to the non-controlling interest (NCI)
Non-GAAP Reconciliation

ADJUSTED EBITDA

Murphy defines Adjusted EBITDA as net income (loss) attributable to Murphy1 before interest, taxes, depreciation, depletion and amortization (DD&A), impairment expense, discontinued operations, foreign exchange gains and losses, mark-to-market gains and losses on derivative instruments, accretion of asset retirement obligations and certain other items that management believes affect comparability between periods.

Adjusted EBITDA is used by management to evaluate the company’s operational performance and trends between periods and relative to its industry competitors.

Adjusted EBITDA may not be comparable to similarly titled measures used by other companies, and it should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). Adjusted EBITDA has certain limitations regarding financial assessments because it excludes certain items that affect net income and net cash provided by operating activities. Adjusted EBITDA should not be considered in isolation or as a substitute for an analysis of Murphy's GAAP results as reported.

<table>
<thead>
<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>EBITDA attributable to Murphy (Non-GAAP)1</td>
<td>375.1</td>
<td>491.7</td>
</tr>
<tr>
<td>Accretion of asset retirement obligations2</td>
<td>10.6</td>
<td>10.2</td>
</tr>
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<td>Write-off of previously suspended exploration well</td>
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<td>0.2</td>
</tr>
<tr>
<td>Loss (gain) on sale of assets2</td>
<td>-</td>
<td>0.7</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA attributable to Murphy (Non-GAAP)</strong></td>
<td><strong>414.4</strong></td>
<td><strong>465.8</strong></td>
</tr>
</tbody>
</table>

1 ‘Attributable to Murphy’ represents the economic interest of Murphy excluding noncontrolling interest in MP GOM
2 Accretion of asset retirement obligations and loss on sale of assets used in the computation of Adjusted EBITDA exclude the portion attributable to the non-controlling interest (NCI)
Non-GAAP Reconciliation

**ADJUSTED EBITDAX**

Murphy defines Adjusted EBITDAX as net income (loss) attributable to Murphy\(^1\) before interest, taxes, depreciation, depletion and amortization (DD&A), exploration expense, impairment expense, discontinued operations, foreign exchange gains and losses, mark-to-market gains and losses on derivative instruments, accretion of asset retirement obligations and certain other items that management believes affect comparability between periods.

Adjusted EBITDAX is used by management to evaluate the company's operational performance and trends between periods and relative to its industry competitors.

Adjusted EBITDAX may not be comparable to similarly titled measures used by other companies, and it should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). Adjusted EBITDAX has certain limitations regarding financial assessments because it excludes certain items that affect net income and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Murphy's GAAP results as reported.

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<td>-</td>
<td>0.7</td>
</tr>
<tr>
<td>Adjusted EBITDAX attributable to Murphy (Non-GAAP)</td>
<td>496.4</td>
<td>504.1</td>
</tr>
</tbody>
</table>

\(^1\) 'Attributable to Murphy' represents the economic interest of Murphy excluding noncontrolling interest in MP GOM  
\(^2\) Accretion of asset retirement obligations, loss on sale of assets and exploration expenses used in the computation of Adjusted EBITDAX exclude the portion attributable to the non-controlling interest (NCI)
Glossary of Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>AECO</strong>: Alberta Energy Company, the Canadian benchmark price for natural gas</td>
<td></td>
</tr>
<tr>
<td><strong>BBL</strong>: Barrels (equal to 42 US gallons)</td>
<td></td>
</tr>
<tr>
<td><strong>BCF</strong>: Billion cubic feet</td>
<td></td>
</tr>
<tr>
<td><strong>BCFE</strong>: Billion cubic feet equivalent</td>
<td></td>
</tr>
<tr>
<td><strong>BN</strong>: Billions</td>
<td></td>
</tr>
<tr>
<td><strong>BOE</strong>: Barrels of oil equivalent (1 barrel of oil or 6,000 cubic feet of natural gas)</td>
<td></td>
</tr>
<tr>
<td><strong>BOEPD</strong>: Barrels of oil equivalent per day</td>
<td></td>
</tr>
<tr>
<td><strong>BOPD</strong>: Barrels of oil per day</td>
<td></td>
</tr>
<tr>
<td><strong>CAGR</strong>: Compound annual growth rate</td>
<td></td>
</tr>
<tr>
<td><strong>D&amp;C</strong>: Drilling and completions</td>
<td></td>
</tr>
<tr>
<td><strong>DD&amp;A</strong>: Depreciation, depletion and amortization</td>
<td></td>
</tr>
<tr>
<td><strong>EACI</strong>: Enterprise adjusted cash income</td>
<td></td>
</tr>
<tr>
<td><strong>EBITDA</strong>: Income from continuing operations before taxes, depreciation, depletion and amortization, and net interest expense</td>
<td></td>
</tr>
<tr>
<td><strong>EBITDAX</strong>: Income from continuing operations before taxes, depreciation, depletion and amortization, net interest expense, and exploration expenses</td>
<td></td>
</tr>
<tr>
<td><strong>EFS</strong>: Eagle Ford Shale</td>
<td></td>
</tr>
<tr>
<td><strong>EUR</strong>: Estimated ultimate recovery</td>
<td></td>
</tr>
<tr>
<td><strong>F&amp;D</strong>: Finding and development</td>
<td></td>
</tr>
<tr>
<td><strong>G&amp;A</strong>: General and administrative expenses</td>
<td></td>
</tr>
<tr>
<td><strong>GOM</strong>: Gulf of Mexico</td>
<td></td>
</tr>
<tr>
<td><strong>IP</strong>: Initial production rate</td>
<td></td>
</tr>
<tr>
<td><strong>LOE</strong>: Lease operating expense</td>
<td></td>
</tr>
<tr>
<td><strong>MBO</strong>: Thousands barrels of oil</td>
<td></td>
</tr>
<tr>
<td><strong>MBOE</strong>: Thousands barrels of oil equivalent</td>
<td></td>
</tr>
<tr>
<td><strong>MBOEPD</strong>: Thousands of barrels of oil equivalent per day</td>
<td></td>
</tr>
<tr>
<td><strong>MBOPD</strong>: Thousands of barrels of oil per day</td>
<td></td>
</tr>
<tr>
<td><strong>MM</strong>: Millions</td>
<td></td>
</tr>
<tr>
<td><strong>MMBOE</strong>: Millions of barrels of oil equivalent</td>
<td></td>
</tr>
<tr>
<td><strong>MMCF</strong>: Millions of cubic feet</td>
<td></td>
</tr>
<tr>
<td><strong>MMCFD</strong>: Millions of cubic feet per day</td>
<td></td>
</tr>
<tr>
<td><strong>NGL</strong>: Natural gas liquids</td>
<td></td>
</tr>
<tr>
<td><strong>ROR</strong>: Rate of return</td>
<td></td>
</tr>
<tr>
<td><strong>R/P</strong>: Ratio of reserves to annual production</td>
<td></td>
</tr>
<tr>
<td><strong>TCF</strong>: Trillion cubic feet</td>
<td></td>
</tr>
<tr>
<td><strong>WI</strong>: Working interest</td>
<td></td>
</tr>
<tr>
<td><strong>WTI</strong>: West Texas Intermediate (a grade of crude oil)</td>
<td></td>
</tr>
<tr>
<td><strong>MCF</strong>: Thousands of cubic feet</td>
<td></td>
</tr>
<tr>
<td><strong>MCFD</strong>: Thousands cubic feet per day</td>
<td></td>
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</tr>
<tr>
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<td></td>
</tr>
</tbody>
</table>
## 1Q 2024 Guidance

<table>
<thead>
<tr>
<th>Producing Asset</th>
<th>Oil (BOPD)</th>
<th>NGLs (BOPD)</th>
<th>Gas (MCFD)</th>
<th>Total (BOEPD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>US – Eagle Ford Shale</td>
<td>19,400</td>
<td>4,400</td>
<td>24,400</td>
<td>27,900</td>
</tr>
<tr>
<td>– Gulf of Mexico excluding NCI&lt;sup&gt;1&lt;/sup&gt;</td>
<td>59,500</td>
<td>4,700</td>
<td>56,500</td>
<td>73,600</td>
</tr>
<tr>
<td>Canada – Tupper Montney</td>
<td>–</td>
<td>–</td>
<td>327,100</td>
<td>54,500</td>
</tr>
<tr>
<td>– Kaybob Duvernay and Placid Montney</td>
<td>2,000</td>
<td>400</td>
<td>7,000</td>
<td>3,600</td>
</tr>
<tr>
<td>– Offshore</td>
<td>7,200</td>
<td>–</td>
<td>–</td>
<td>7,200</td>
</tr>
<tr>
<td>Other</td>
<td>200</td>
<td>–</td>
<td>–</td>
<td>200</td>
</tr>
</tbody>
</table>

1Q Production Volume (BOEPD) excl. NCI<sup>1</sup>  
1Q Exploration Expense ($MM)  
Full Year 2024 CAPEX ($MM) excl. NCI<sup>2</sup>  
Full Year 2024 Production Volume (BOEPD) excl. NCI<sup>3</sup>

163,000 – 171,000  
$24  
$920 – $1,020  
180,000 – 188,000

<sup>1</sup> Excludes noncontrolling interest of MP GOM of 6,300 BOPD oil, 300 BOPD NGLs and 2,500 MCFD gas  
<sup>2</sup> Excludes noncontrolling interest of MP GOM of $22 MM  
<sup>3</sup> Excludes noncontrolling interest of MP GOM of 6,400 BOPD oil, 300 BOPD NGLs and 2,500 MCFD gas
## Current Fixed Price Contracts – Natural Gas

### Tupper Montney, Canada

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (MMCF/D)</th>
<th>Price (MCF)</th>
<th>Start Date</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales at AECO</td>
<td>162</td>
<td>C$2.39</td>
<td>1/1/2024</td>
<td>12/31/2024</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales at AECO</td>
<td>25</td>
<td>US$1.98</td>
<td>1/1/2024</td>
<td>10/31/2024</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales at AECO</td>
<td>15</td>
<td>US$1.98</td>
<td>11/1/2024</td>
<td>12/31/2024</td>
</tr>
</tbody>
</table>

As of January 23, 2024

Note: These contracts are for physical delivery of natural gas volumes at a fixed price, with no mark-to-market income adjustment.
North America Onshore Locations
More Than 50 Years of Robust Inventory with Low Breakeven Rates

Diversified, Low Breakeven Portfolio
- Multi-basin portfolio provides optionality in all price environments
- Focus on capital efficiency
- Culture of continuous improvement leads to value-added shared learnings

Eagle Ford Shale and Kaybob Duvernay
- > 25 years of inventory < $50 / BBL
- ~ 55 years of total inventory
- >15 years of Eagle Ford Shale inventory < $50 / BBL

Tupper Montney
- ~ 50 years of inventory

As of December 31, 2023
Note: Breakeven rates are based on estimated costs of a 4-well pad program at a 10% rate of return. Tupper Montney inventory assumes an annual 20-well program. Eagle Ford Shale and Kaybob Duvernay combined inventory, and Eagle Ford Shale standalone inventory, assume an annual 30-well program.
Offshore Development Opportunities
Multi-Year Inventory of High-Return Projects

Diversified, Low Breakeven Opportunities in Offshore Portfolio

- Multi-year inventory of identified offshore projects in current portfolio
- Maintaining annual offshore production of 90 – 100 MBOEPD with average annual CAPEX of ~$380 MM from FY 2024 – FY 2028
- Projects include
  - 37 projects – 209 MMBOE of total resources with < $35 / BBL WTI breakeven
  - 8 projects – 20 MMBOE of total resources with $35 to $50 / BBL WTI breakeven

Identified Offshore Project Portfolio
Number of Projects

<table>
<thead>
<tr>
<th>Breakeven Oil Price ($ / BBL WTI)</th>
<th>Number of Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; $35</td>
<td>37</td>
</tr>
<tr>
<td>$35 - $40</td>
<td>-</td>
</tr>
<tr>
<td>$40 - $45</td>
<td>13</td>
</tr>
<tr>
<td>$45 - $50</td>
<td>-</td>
</tr>
<tr>
<td>&gt; $50</td>
<td>-</td>
</tr>
</tbody>
</table>

Identified Offshore Project Portfolio
Percent MMBOE by Area

- Gulf of Mexico: 77%
- SE Asia: 13%
- Offshore Canada: 10%

As of December 31, 2023
Note: Breakeven rates are based on current estimated costs at a 10% rate of return
## North America Onshore Well Locations

### Eagle Ford Shale Operated Well Locations

<table>
<thead>
<tr>
<th>Area</th>
<th>Net Acres</th>
<th>Reservoir</th>
<th>Inter-Well Spacing (ft)</th>
<th>Gross Remaining Locations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Karnes</td>
<td>10,155</td>
<td>Lower EFS</td>
<td>300</td>
<td>91</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>850</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>1,100</td>
<td>104</td>
</tr>
<tr>
<td>Tilden</td>
<td>61,611</td>
<td>Lower EFS</td>
<td>600</td>
<td>202</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>1,200</td>
<td>51</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>1,200</td>
<td>86</td>
</tr>
<tr>
<td>Catarina</td>
<td>47,733</td>
<td>Lower EFS</td>
<td>560</td>
<td>190</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>1,280</td>
<td>189</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>1,600</td>
<td>97</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>119,549</strong></td>
<td></td>
<td></td>
<td><strong>1,160</strong></td>
</tr>
</tbody>
</table>

### Tupper Montney Well Locations

<table>
<thead>
<tr>
<th>Area</th>
<th>Net Acres</th>
<th>Inter-Well Spacing (ft)</th>
<th>Gross Remaining Locations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tupper Montney</td>
<td>118,235</td>
<td>984 - 1,323</td>
<td>976</td>
</tr>
</tbody>
</table>

### Kaybob Duvernay Well Locations

<table>
<thead>
<tr>
<th>Area</th>
<th>Net Acres</th>
<th>Inter-Well Spacing (ft)</th>
<th>Gross Remaining Locations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two Creeks</td>
<td>28,064</td>
<td>984</td>
<td>120</td>
</tr>
<tr>
<td>Kaybob East</td>
<td>32,825</td>
<td>984</td>
<td>152</td>
</tr>
<tr>
<td>Kaybob West</td>
<td>26,192</td>
<td>984</td>
<td>103</td>
</tr>
<tr>
<td>Kaybob North</td>
<td>23,604</td>
<td>984</td>
<td>113</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>110,685</strong></td>
<td></td>
<td><strong>488</strong></td>
</tr>
</tbody>
</table>

As of December 31, 2023
Eagle Ford Shale
Peer Acreage

Acreage as of January 23, 2024

[Map showing acreage for various companies like Murphy, 1776, Black Mountain Oil, BPX, Conoco, Crescent Energy, Devon Energy, EOG, EP Energy, Grit Oil & Gas, Endeavor, INEOS, Lewis/BPX, Marathon, Mesquite Energy, Repsol, Ridgemar, Silverbow, and SM Energy.]
Tupper Montney
Peer Acreage

Acreage as of January 23, 2024
## Gulf of Mexico
### Murphy Blocks

<table>
<thead>
<tr>
<th>Asset</th>
<th>Operator</th>
<th>Murphy WI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calliope</td>
<td>Murphy</td>
<td>29%</td>
</tr>
<tr>
<td>Cascade</td>
<td>Murphy</td>
<td>80%</td>
</tr>
<tr>
<td>Chinook</td>
<td>Murphy</td>
<td>86%</td>
</tr>
<tr>
<td>Clipper</td>
<td>Murphy</td>
<td>80%</td>
</tr>
<tr>
<td>Dalmatian</td>
<td>Murphy</td>
<td>56%</td>
</tr>
<tr>
<td>Front Runner</td>
<td>Murphy</td>
<td>50%</td>
</tr>
<tr>
<td>Habanero</td>
<td>Shell</td>
<td>27%</td>
</tr>
<tr>
<td>Khaleesi</td>
<td>Murphy</td>
<td>34%</td>
</tr>
<tr>
<td>Kodiak</td>
<td>Kosmos</td>
<td>59%</td>
</tr>
<tr>
<td>Lucius</td>
<td>Anadarko</td>
<td>16%</td>
</tr>
<tr>
<td>Marmalard</td>
<td>Murphy</td>
<td>24%</td>
</tr>
<tr>
<td>Marmalard East</td>
<td>Murphy</td>
<td>65%</td>
</tr>
<tr>
<td>Medusa</td>
<td>Murphy</td>
<td>48%</td>
</tr>
<tr>
<td>Mormont</td>
<td>Murphy</td>
<td>34%</td>
</tr>
<tr>
<td>Nearly Headless Nick</td>
<td>Murphy</td>
<td>27%</td>
</tr>
<tr>
<td>Neidermeyer</td>
<td>Murphy</td>
<td>53%</td>
</tr>
<tr>
<td>Powerball</td>
<td>Murphy</td>
<td>75%</td>
</tr>
<tr>
<td>Samurai</td>
<td>Murphy</td>
<td>50%</td>
</tr>
<tr>
<td>Son of Bluto II</td>
<td>Murphy</td>
<td>27%</td>
</tr>
<tr>
<td>St. Malo</td>
<td>Chevron</td>
<td>20%</td>
</tr>
<tr>
<td>Tahoe</td>
<td>W&amp;T</td>
<td>24%</td>
</tr>
</tbody>
</table>

### PRODUCING ASSETS

- **Asset Operator**
  - Calliope: Murphy (29%)
  - Cascade: Murphy (80%)
  - Chinook: Murphy (86%)
  - Clipper: Murphy (80%)
  - Dalmatian: Murphy (56%)
  - Front Runner: Murphy (50%)
  - Habanero: Shell (27%)
  - Khaleesi: Murphy (34%)
  - Kodiak: Kosmos (59%)
  - Lucius: Anadarko (16%)
  - Marmalard: Murphy (24%)
  - Marmalard East: Murphy (65%)
  - Medusa: Murphy (48%)
  - Mormont: Murphy (34%)
  - Nearly Headless Nick: Murphy (27%)
  - Neidermeyer: Murphy (53%)
  - Powerball: Murphy (75%)
  - Samurai: Murphy (50%)
  - Son of Bluto II: Murphy (27%)
  - St. Malo: Chevron (20%)
  - Tahoe: W&T (24%)

### Notes:
- Acreage as of January 23, 2024
- 1 Excluding noncontrolling interest
- 2 Anadarko is a wholly-owned subsidiary of Occidental Petroleum

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**www.murphyoilcorp.com**

**NYSE: MUR**
Exploration Update
Sergipe-Alagoas Basin, Brazil

Asset Overview

- ExxonMobil 50% (Op), Enauta Energia S.A. 30%, Murphy 20%
- Hold WI in 9 blocks, spanning >1.6 MM gross acres
- >2.8 BN BOE discovered in basin
- >1.2 BN BOE in deepwater since 2007
- Evaluating next steps with partners

Acreage as of January 23, 2024

All blocks begin with SEAL-M
Exploration Update
Potiguar Basin, Brazil

Asset Overview
• Murphy 100% (Op)
• Hold WI in 3 blocks, spanning ~775 M gross acres
• Proven oil basin in proximity to Pitu oil discovery

Extending the Play Into the Deepwater
• >2.1 BBOE discovered in basin
  • Onshore and shelf
  • Pitu was first step-out into deepwater
• Monitoring nearby key industry wells

Acreage as of January 23, 2024