MURPHY
OIL CORPORATION

2023
FOURTH QUARTER EARNINGS

CONFERENCE CALL & WEBCAST

JANUARY 25, 2024

ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER

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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[1] 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

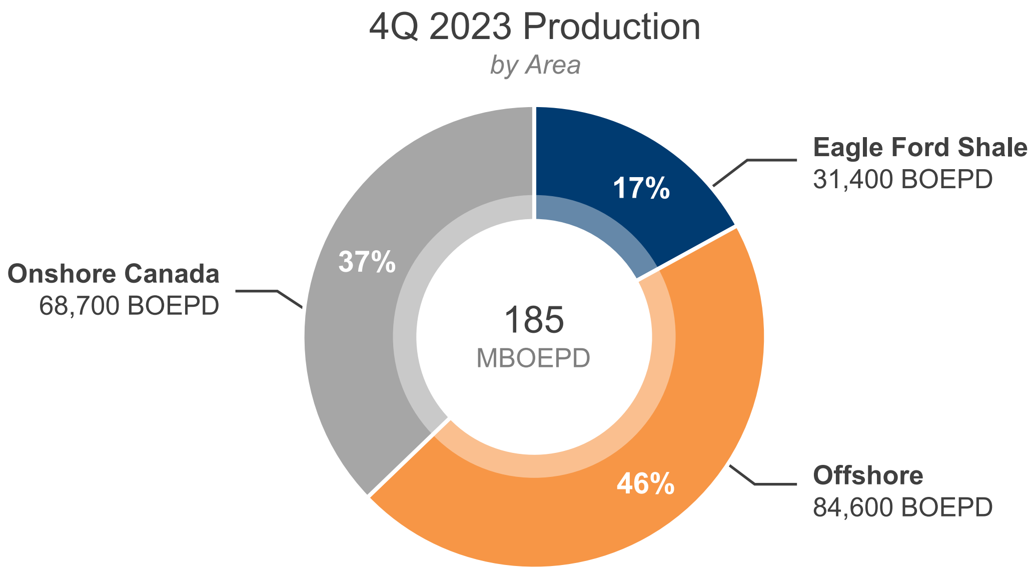
Progressed Murphy 2.0 of Capital Allocation Framework[1]

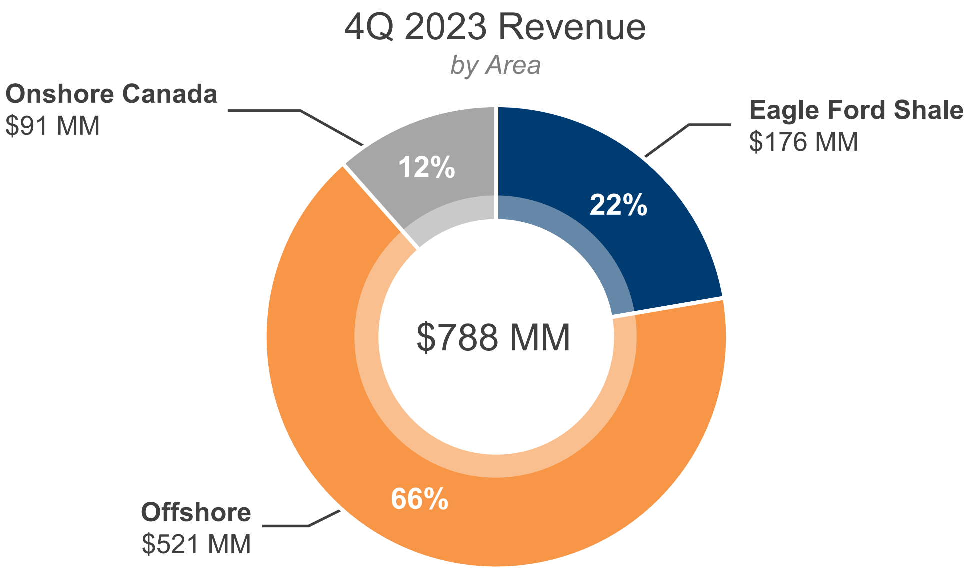
- Repurchased $150 MM, or 3.4 MM shares, at an average price of $43.96 / share in FY 2023
- $450 MM remaining under share repurchase authorization as of Dec 31, 2023
- Announced 9% dividend increase of quarterly cash dividend to $1.20 / share annualized in 1Q 2024

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

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

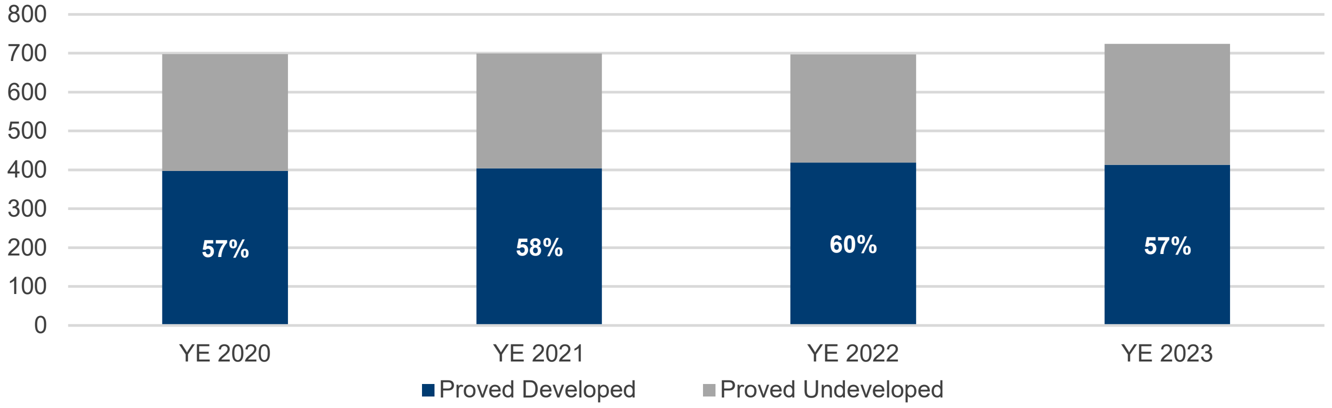
Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated
Prices are shown excluding hedges and before transportation, gathering, processing. Revenue is from production only and excludes sales from purchased gas

2023 Proved Reserves

Maintaining Proved Reserves and Reserve Life

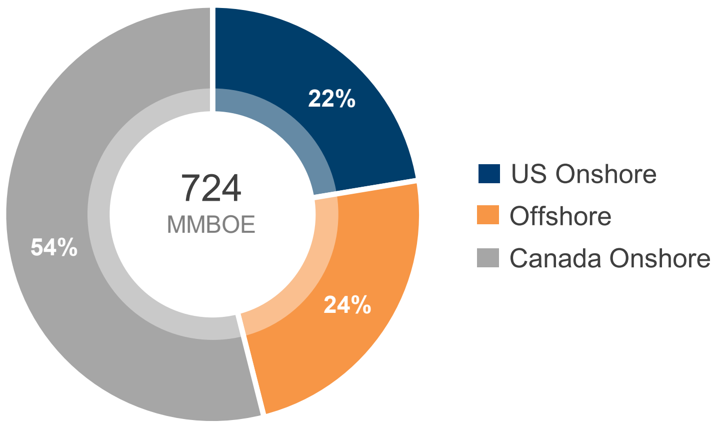
- Total proved reserves 724 MMBOE at YE 2023 vs 697 MMBOE at YE 2022
  - Achieved 139% total reserve replacement
- Added ~13 MMBOE of proved reserves for Lac Da Vang field in Vietnam
- Maintained proved reserves from FY 2020 – FY 2023 with average annual CAPEX of ~$1.07 BN, excluding NCI and including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

Proved Reserves *MMBOE*



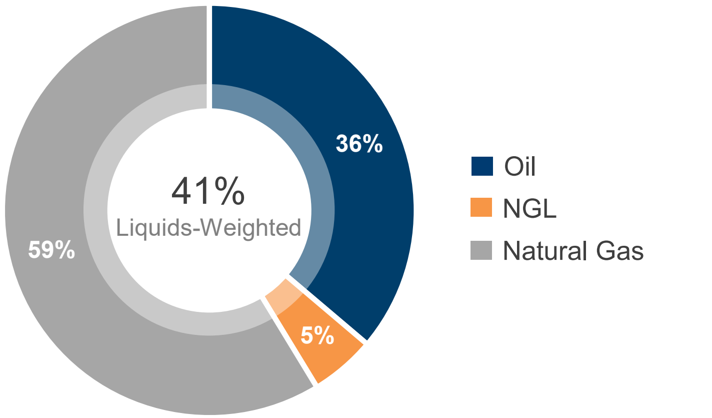
2023E Proved Reserves

By Area



2023E Proved Reserves

By Product



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

Net Income Attributable to Murphy *($MM Except Per Share)*	**4Q 2023**	**FY 2023**
Income (loss)	$116	$662
$/Diluted share	$0.75	$4.22

Adjusted Income from Continuing Ops.	**4Q 2023**	**FY 2023**
Adjusted income (loss)	$140	$709
$/Diluted share	$0.90	$4.52

Adj. EBITDA Attributable to Murphy *($MM)*	**4Q 2023**	**FY 2023**
EBITDA attributable to Murphy	$375	$1,807
Accretion of asset retirement obligations	$11	$41
Foreign exchange loss and other	$28	$53
Adjusted EBITDA	**$414**	**$1,901**

Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated

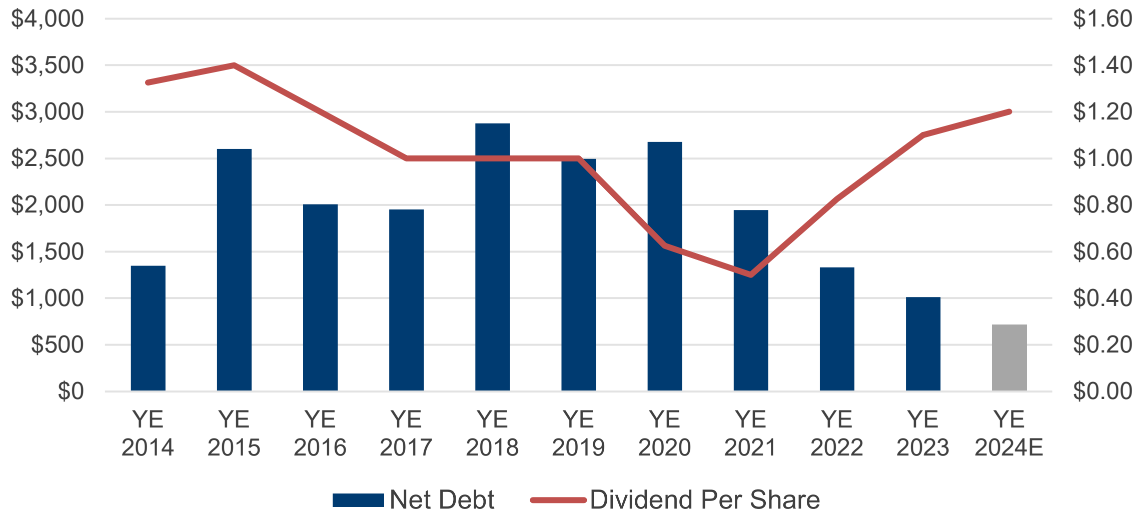
Financial Results
Strengthening Balance Sheet

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

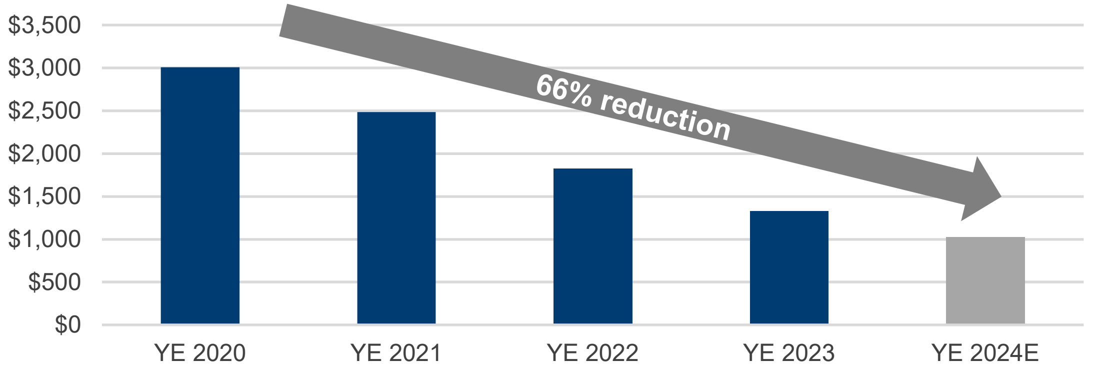
De-Risking Balance Sheet While Enhancing Dividend
- Increased quarterly dividend 9% in 1Q 2024 to $1.20 / share annualized, restoring to 2016 level
- ~64% decrease in net debt since YE 2016

Long-Term Debt Profile[1]
- Total senior notes outstanding: $1.3 BN
- Weighted avg fixed coupon: 6.2%
- Weighted avg maturity: 8.1 years
  - Next maturity Dec 2027

Historical Dividend Per Share and Net Debt *$MM*



Total Debt Outstanding[1] *$MM*



1 As of December 31, 2023

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

~75% of adjusted FCF allocated to debt reduction

~25% distributed through share buybacks and potential dividend increases

Murphy 3.0 –
Long-Term Debt
≤ $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

Cash Flow From Operations Before WC Change

(-) Capital expenditures

= Free Cash Flow

(-) Distributions to NCI and projected payments[3]

(-) Quarterly dividend

(-) Accretive acquisitions

= Adjusted Free Cash Flow (Adjusted FCF)

$450 MM Remaining Share Repurchase Program[2] Authorized by Board

[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

Sustainability Highlights

Taking Action to Benefit All Stakeholders

CONTINUED **ENVIRONMENTAL** STEWARDSHIP

ADVANCING OUR **CLIMATE GOALS**

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

ZERO
ROUTINE FLARING
by 2030

LOWEST
EMISSIONS INTENSITIES
since 2013

HIGHEST
WATER RECYCLING RATIO
in company history

ZERO
IOGP SPILLS
in 2021 and 2022

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

2023 Exploration Update

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 Exploration Focus Areas

2024 CAPITAL AND PRODUCTION PLAN

MURPHY OIL CORPORATION

2024 Capital Plan

Prioritizing Capital To Maximize Production and Adjusted Free Cash Flow[1]

Further Delevering, Enhancing Shareholder Returns

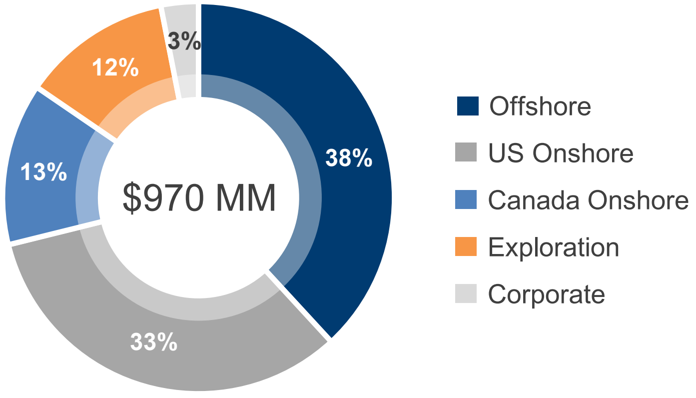
- FY 2024 guidance $920 MM – $1.02 BN CAPEX
- ~60% of spend is in 1H 2024
- ~85% of capital is for development
  - 80% of development capital is operated

Targeting Murphy 3.0 in 2024

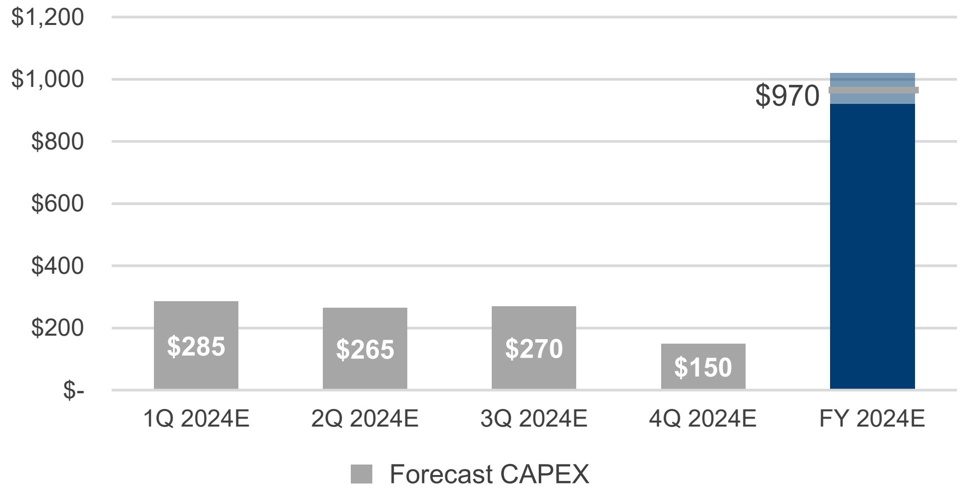
- $300 MM debt reduction goal in 2024[2]
- Increased dividend in 1Q 2024 to $1.20 / share annualized
- Share repurchases to equal 25% of adjusted FCF[1] until goal reached

FY 2024E CAPEX

By Area



2024E Accrued CAPEX by Quarter *$ MM*



Accrual CAPEX, based on midpoint of guidance range and excluding noncontrolling interest
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

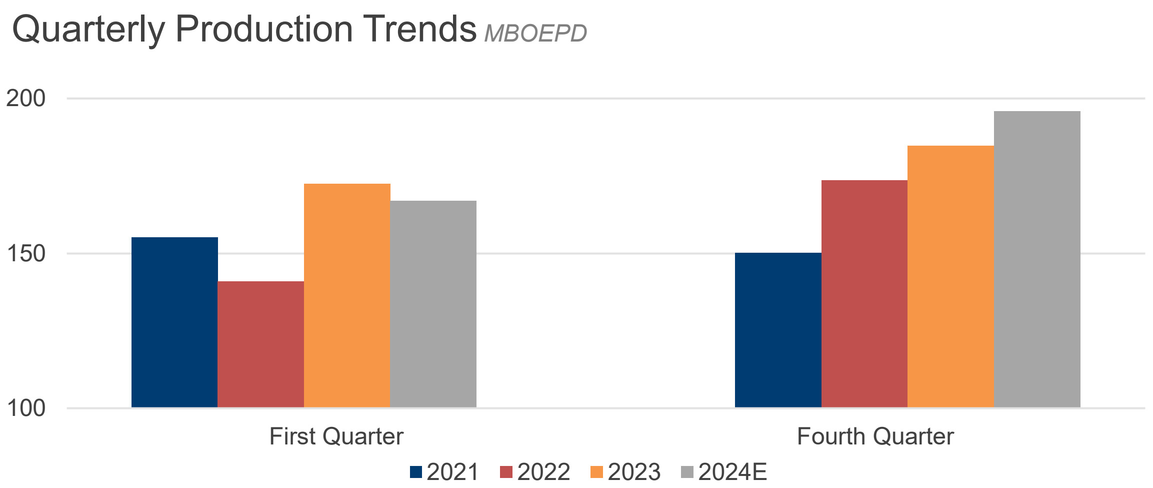
2024 Production Plan

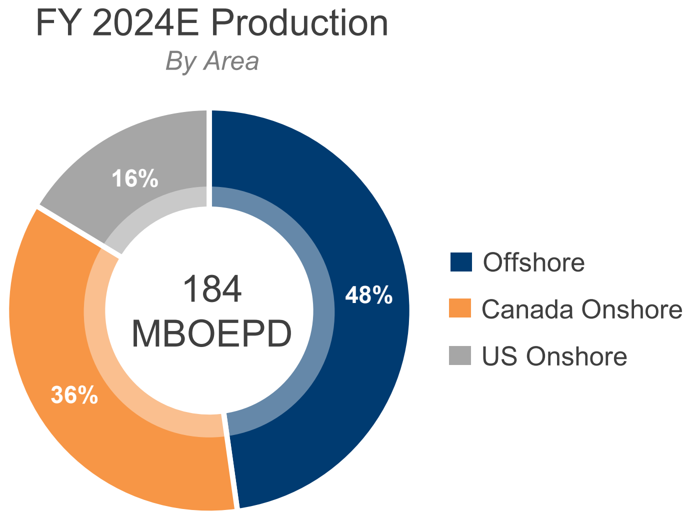
1Q 2024 Production Guidance 163 – 171 MBOEPD

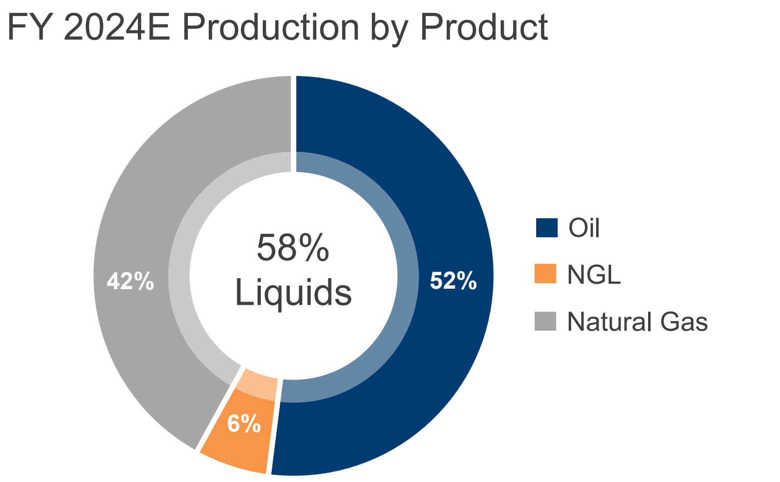
- 89 MBOPD or 53% oil, 59% liquids volumes
- Includes planned downtime of:
  - 13 MBOEPD of total Gulf of Mexico downtime, comprised of:
    - 6 MBOEPD for workovers; will return to production 1H 2024
    - 5 MBOEPD for planned facility and downstream maintenance
    - 2 MBOEPD for subsea equipment repair 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







Eagle Ford Shale

Enhancing Portfolio and Production Through Strong Execution, Improved Completions

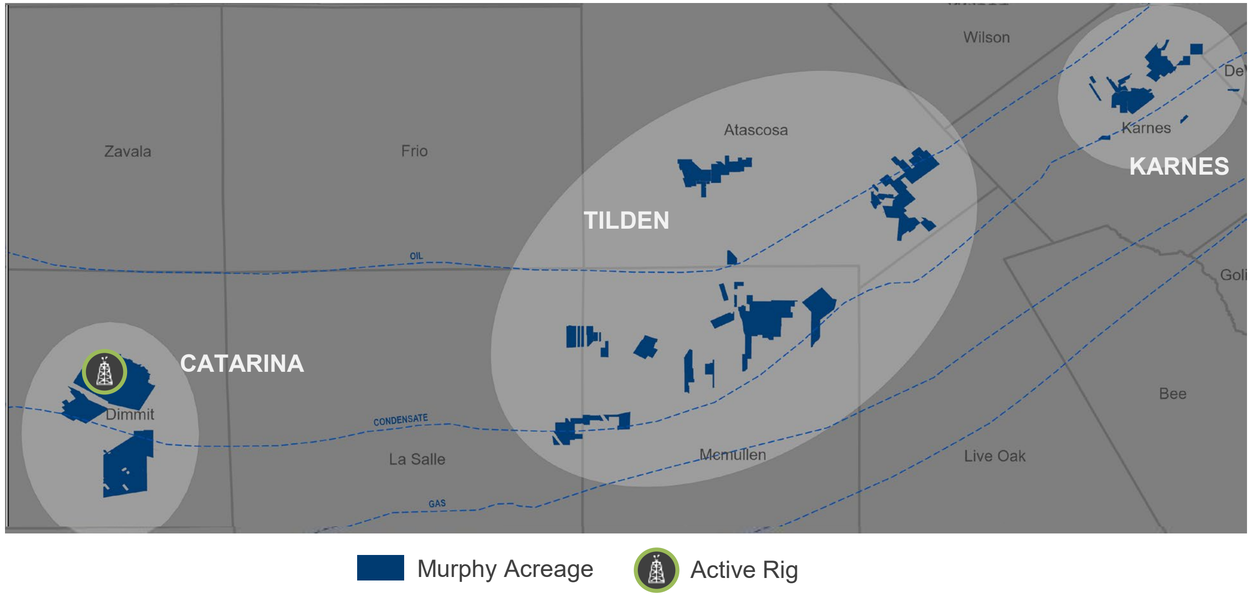
$320 MM 2024 Capital Budget, ~30 MBOEPD

- 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

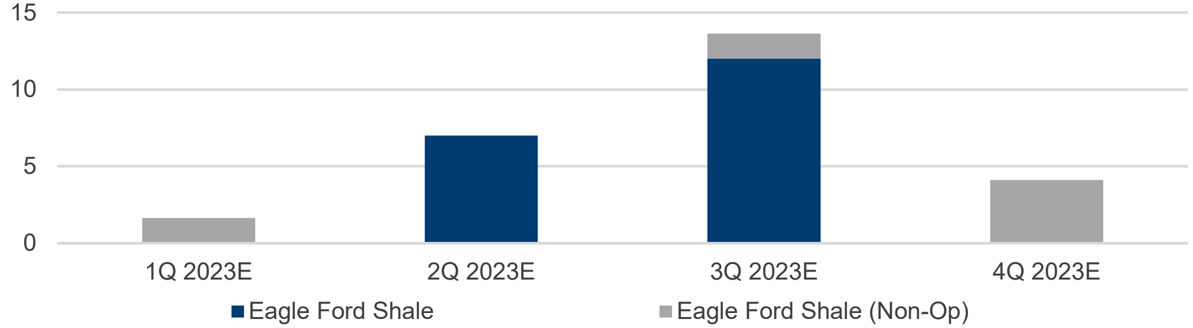
Strong Performance Across Locations

- 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

Acreage as of January 23, 2024

Tupper Montney

New Completions Design Drives Strong Well Performance

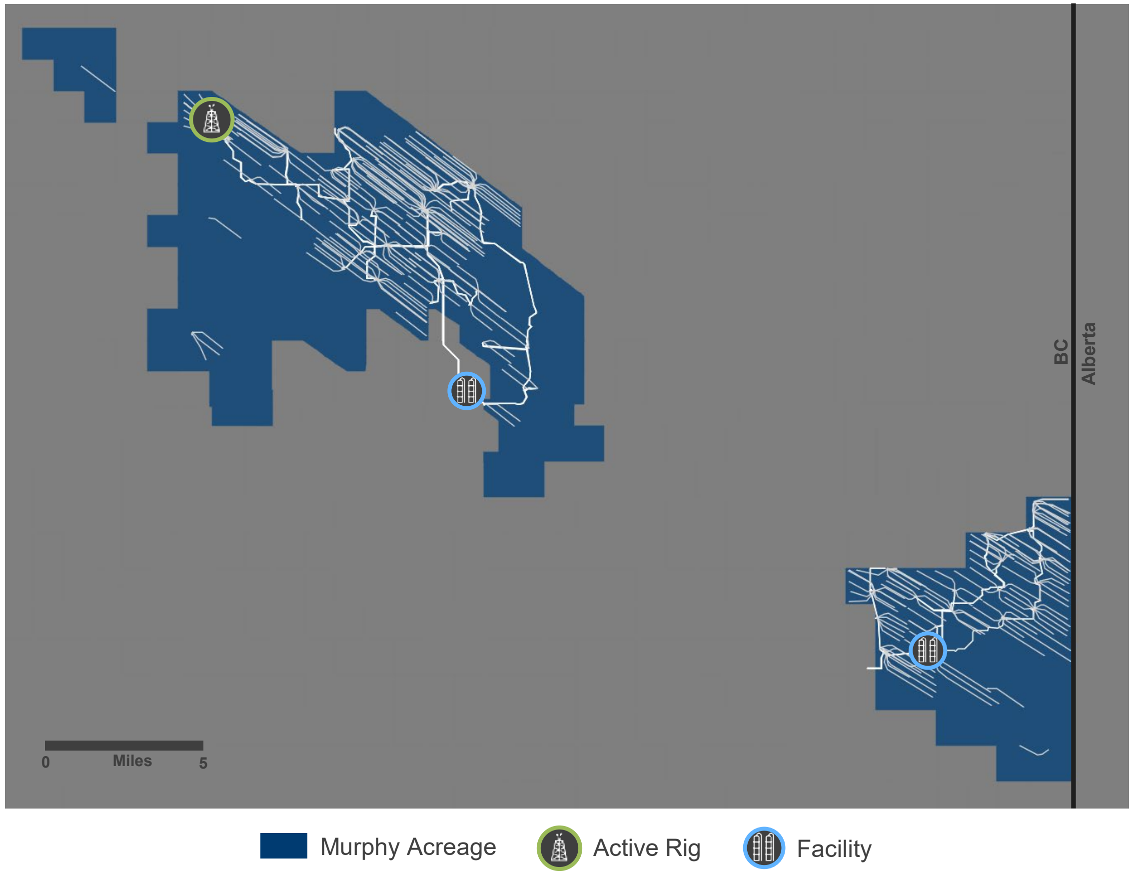
$90 MM 2024 Capital Budget, ~370 MMCFD

- 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[1]
- Achieving some of highest IP30 rates in company history
- Optimizing fracs in real-time

Tupper Montney Acreage



1 BOE Report dated August 31, 2023

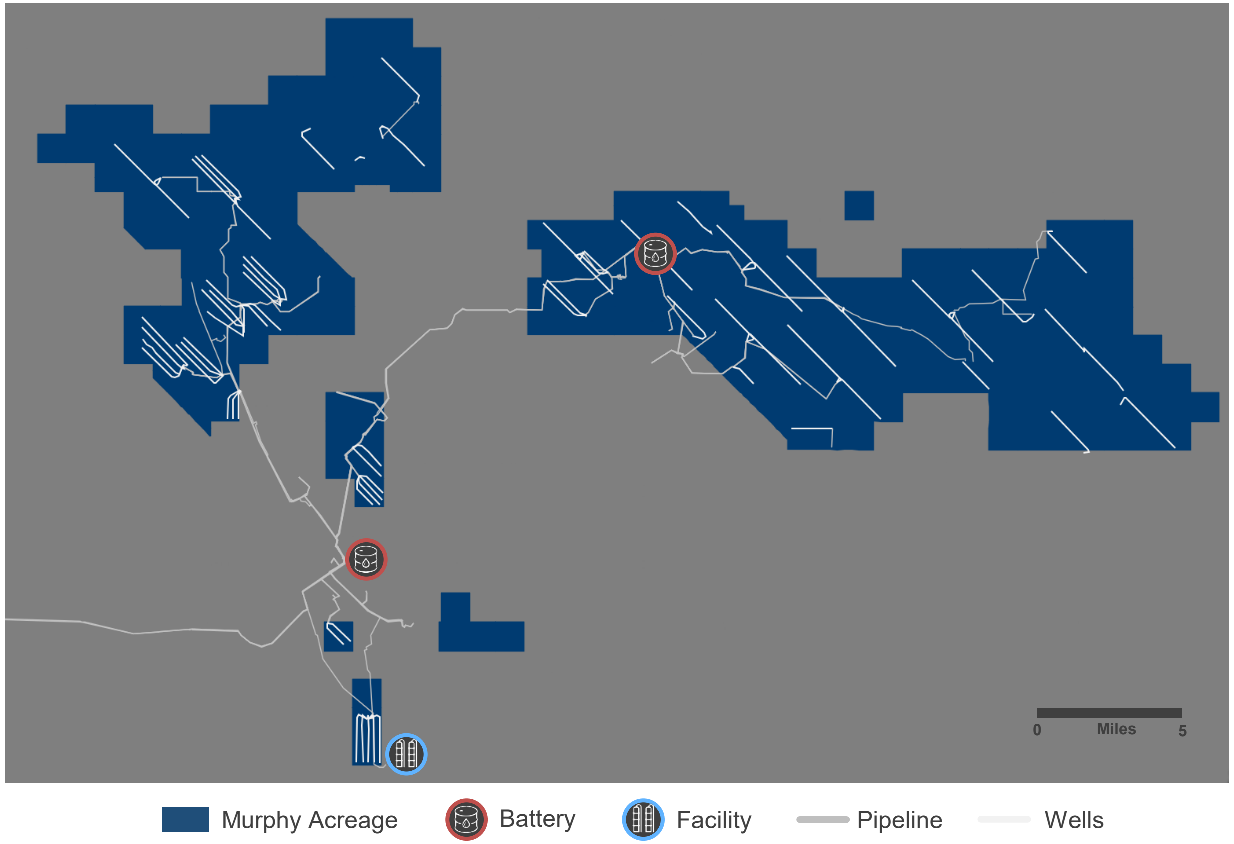
Acreage as of January 23, 2024

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

Kaybob Duvernay Acreage



Acreage as of January 23, 2024

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

Field	Drilling	Completions	Online
Marmalard	✓	✓	1Q 2024
Khaleesi	●		2Q 2024
Mormont	● ●		3-4Q 2024
Samurai	●		2025
Dalmatian	●		2025
Longclaw	✓		2026
St. Malo (non-op)	✓	✓	1Q 2024
Lucius (non-op)	● ● ●		1H 2024-2025

● Planned well ✓ Drilling in progress ✓ Drilled well

Offshore Canada Development Projects

Field	Activity	Online
Hibernia (non-op)	5 development wells	2024

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 value 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

Field	Location	Project	Online	Net Production
Marmalard	Mississippi Canyon 255	Zone changes	1Q 2024	~1.5 MBOEPD
Mormont	Mississippi Canyon 478	Subsea equipment repair	1Q 2024	~5 MBOEPD
Neidermeyer	Mississippi Canyon 208	Workover	2Q 2024	~4.0 MBOEPD
Dalmatian	DeSoto Canyon 4	Subsurface safety valve repair	Mid-2024	~1.5 MBOEPD

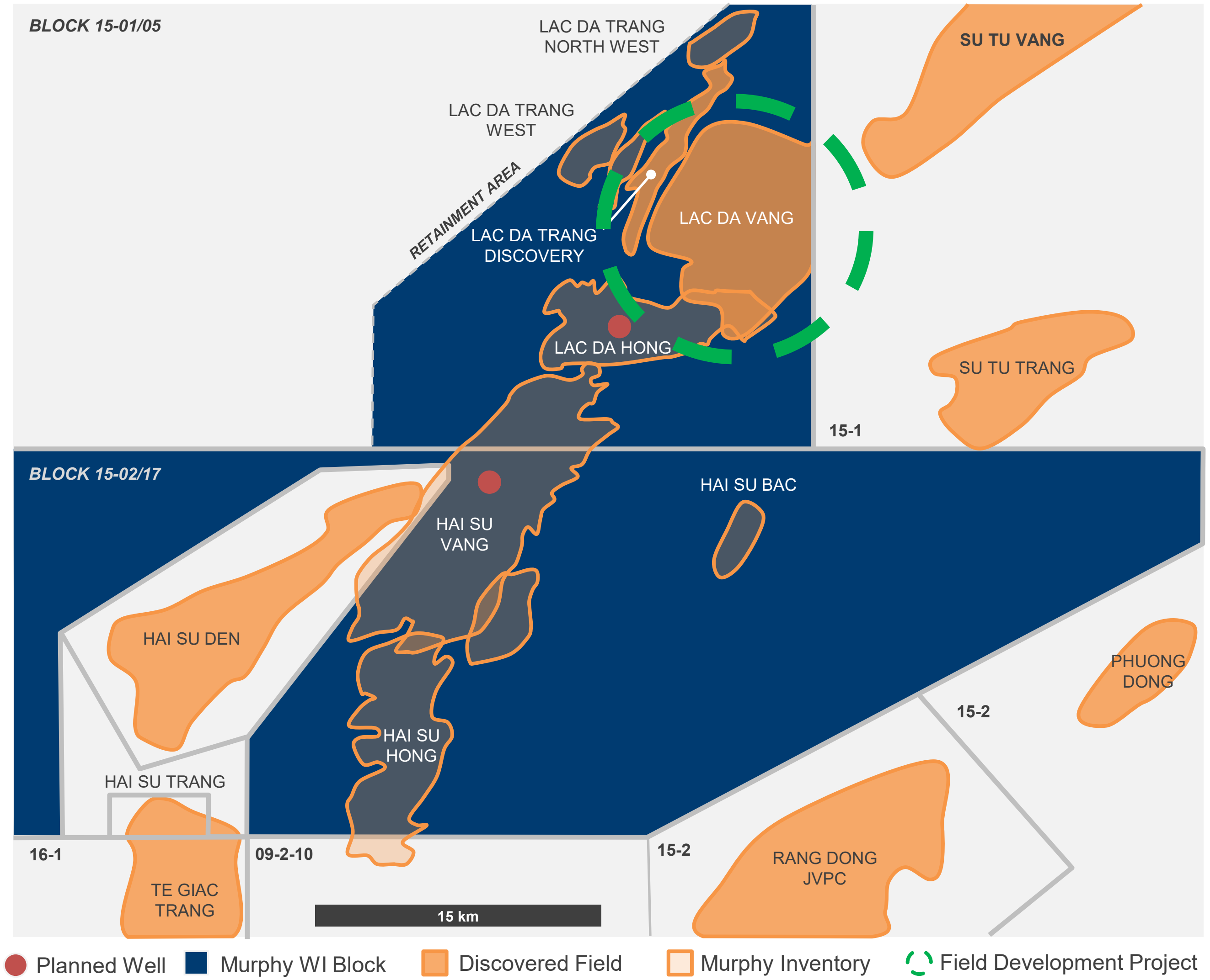
Non-Operated Workovers and Projects

Field	Location	Project	Online	Net Production
Lucius	Keathley Canyon 919	Workover	1Q 2024	~1.0 MBOEPD
Kodiak	Mississippi Canyon 727	Stimulation / zone addition	Mid-2024	~1.0 MBOEPD incremental

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

Cuu Long Basin



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

2024 Exploration Plan

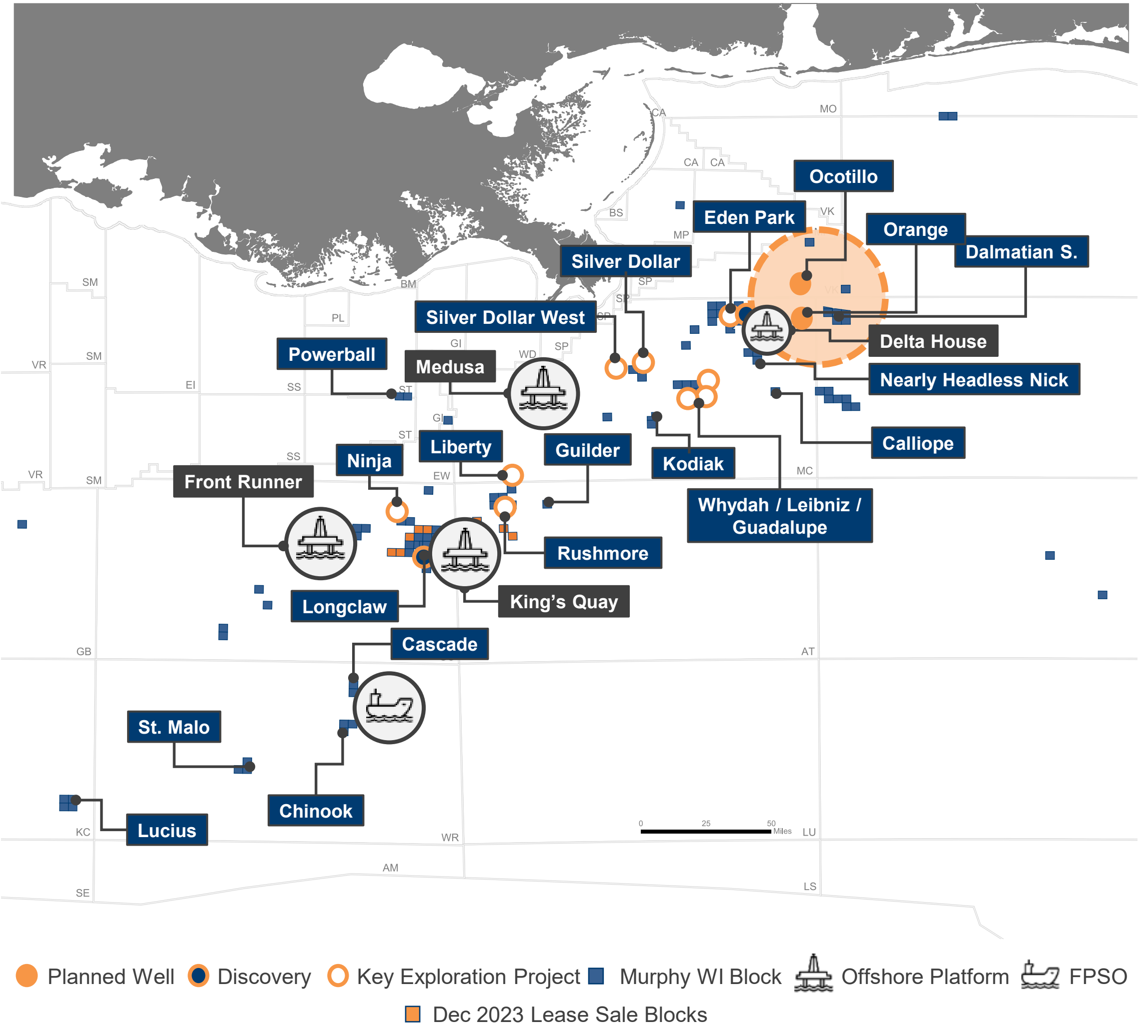
$120 MM 2024 Total Exploration Capital Budget

- 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

Gulf of Mexico Assets



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

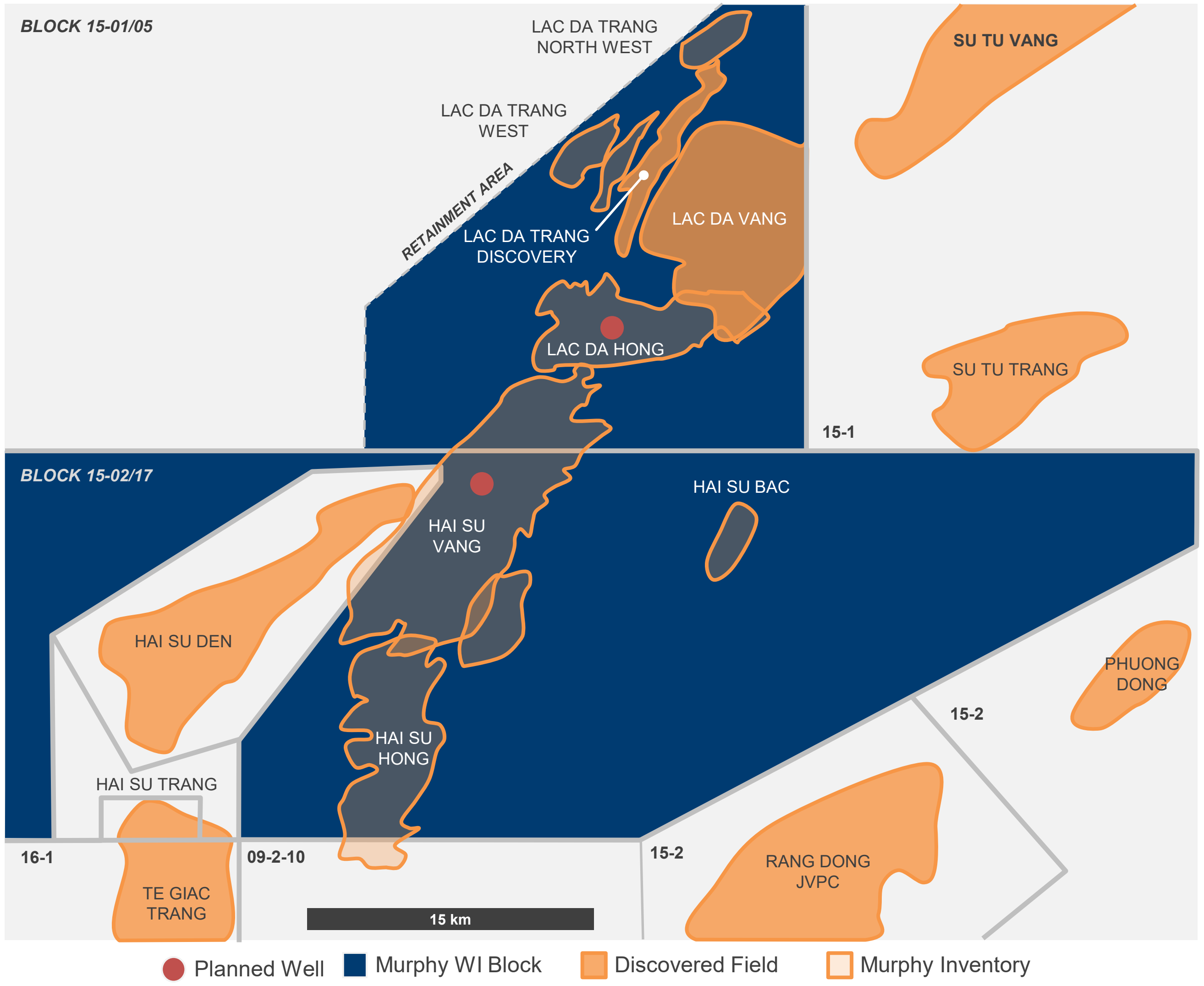
- Advancing plans for Lac Da Hong exploration well
  - Targeting spud 4Q 2024
- Mean to upward gross resource potential
  - 65 MMBOE – 135 MMBOE

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

Cuu Long Basin



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[1] 10%

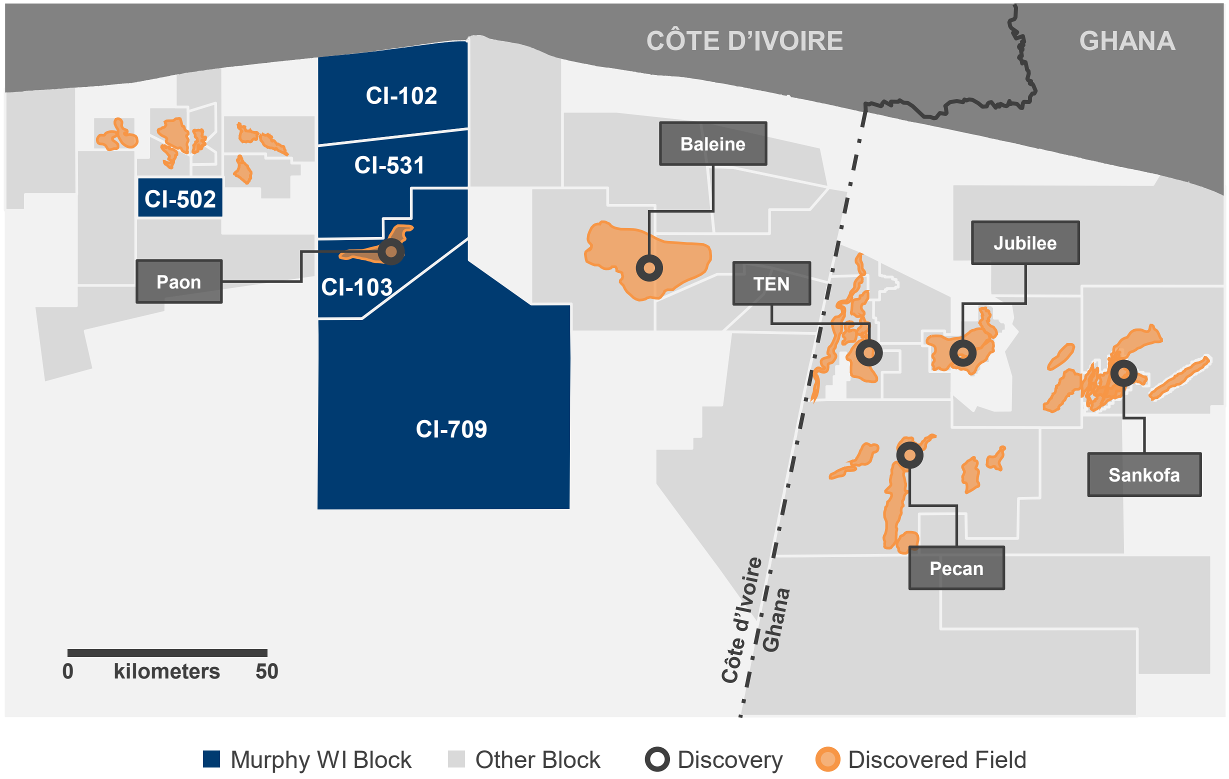
Block CI-103

- Murphy 85% (Op), PETROCI[1] 15%

Includes Undeveloped Paon Discovery

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

Tano Basin



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

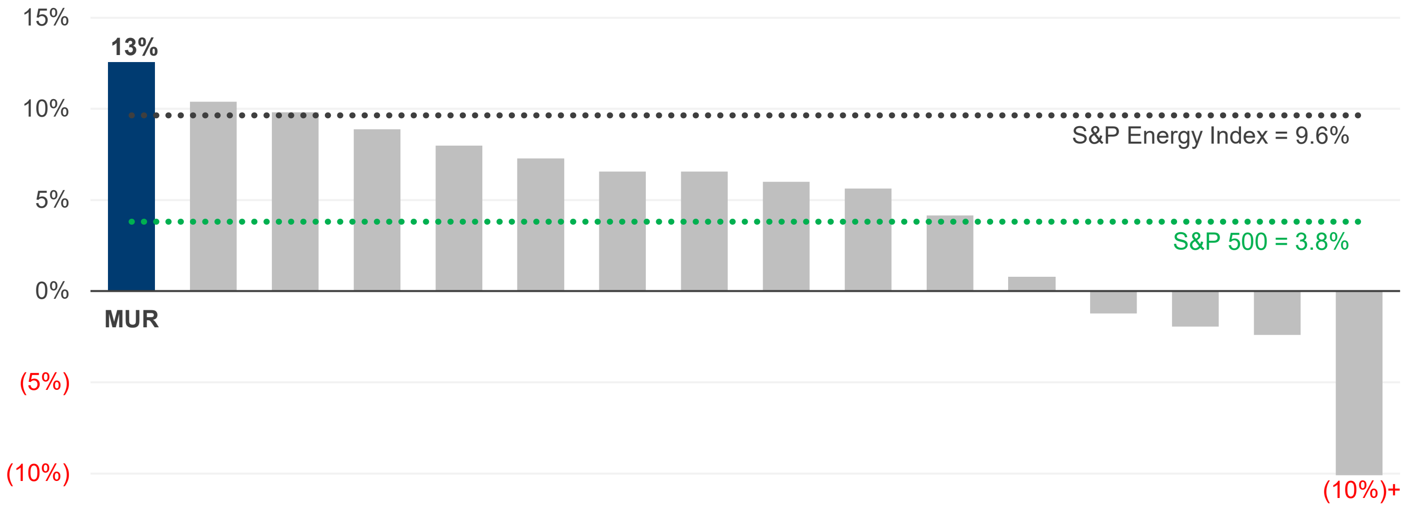
Financial Strength Provides Low Risk to Sustainable Returns

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

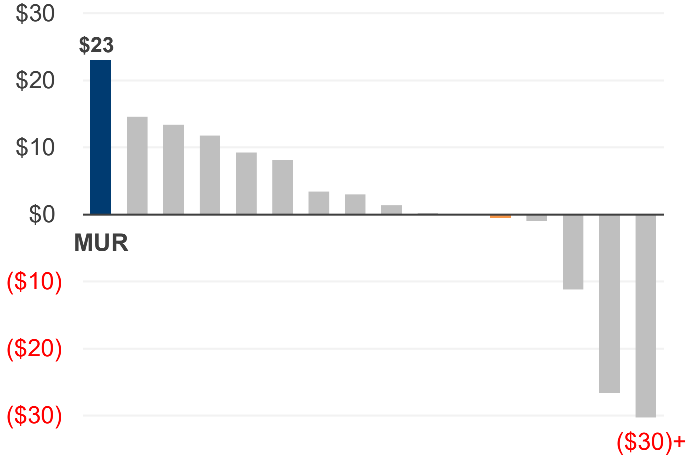
Plan Reflects Metrics That Support Additional Cash Return Growth

- 2024 plan achieves $1.0 BN debt target
- Murphy 3.0 of capital allocation framework provides > 50% payout of adjusted FCF[1]

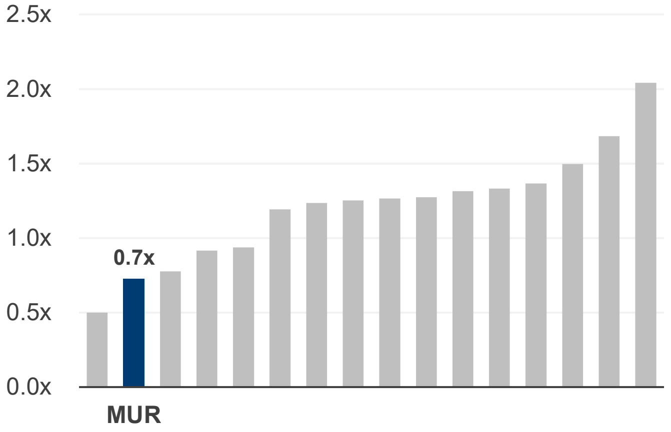
Free Cash Flow Yield – TTM[2] *By Percentage*



Free Cash Flow / Production[2] *$ / BOE*



Debt-to-EBITDA – TTM[2]



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

Disciplined Strategy Leads to Long-Term Value With Current Assets

	NEAR-TERM	LONG-TERM
DELEVER EXECUTE EXPLORE RETURN	• Reducing debt by $300 MM to reach $1.0 BN debt target in 2024[1] with no debt maturities until Dec 2027 • Reinvesting ~50% of operating cash flow[1] 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 delevering • 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	• Realizing average annual production of 210-220 MBOEPD with > 50% average oil weighting • Reinvesting ~45% of operating cash flow[1] • 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
	2024 | 2025 | 2026	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

DELEVER | EXECUTE | EXPLORE | RETURN

2023
FOURTH QUARTER EARNINGS

CONFERENCE CALL & WEBCAST

JANUARY 25, 2024

ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER

FUTURE
performance | progress | people

Appendix

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)	Three Months Ended – Dec 31, 2023	Three Months Ended – Dec 31, 2022
Net income attributable to Murphy (GAAP)[1]	116.3	199.4
Discontinued operations loss	0.7	0.2
Net income from continuing operations attributable to Murphy	**117.0**	**199.6**
Adjustments[2]:		
Write-off of previously suspended exploration well	-	22.7
Asset retirement obligation losses	16.9	30.8
Foreign exchange loss (gain)	11.1	5.7
Mark-to-market (gain) on contingent consideration	-	(20.2)
Mark-to-market (gain) on derivative instruments	-	(76.0)
Loss (gain) on sale of assets	-	0.7
Early redemption of debt cost	-	3.5
Total adjustments, before taxes	**28.0**	**(32.8)**
Income tax expense (benefit) related to adjustments	(5.0)	6.5
Total adjustments after taxes	**23.0**	**(26.3)**
Adjusted net income from continuing operations attributable to Murphy (Non-GAAP)	**140.0**	**173.3**
Adjusted net income from continuing operations per average diluted share (Non-GAAP)	**0.90**	**1.10**

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 Murphy[1] 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.

(Millions of dollars)	Three Months Ended – Dec 31, 2023	Three Months Ended – Dec 31, 2022
Net income attributable to Murphy (GAAP)[1]	**116.3**	**199.4**
Income tax expense	29.1	61.9
Interest expense, net	23.7	34.7
Depreciation, depletion and amortization expense[2]	206.0	195.7
EBITDA attributable to Murphy (Non-GAAP)	**375.1**	**491.7**
Exploration expenses[2]	82.0	61.0
EBITDAX attributable to Murphy (Non-GAAP)	**457.1**	**552.7**

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 Murphy[1] 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.

(Millions of dollars)	Three Months Ended – Dec 31, 2023	Three Months Ended – Dec 31, 2022
EBITDA attributable to Murphy (Non-GAAP)[1]	375.1	491.7
Accretion of asset retirement obligations[2]	10.6	10.2
Write-off of previously suspended exploration well	-	22.7
Asset retirement obligation losses	16.9	30.8
Foreign exchange loss (gain)	11.1	5.7
Mark-to-market (gain) loss on contingent consideration	-	(20.2)
Mark-to-market (gain) on derivative instruments	-	(76.0)
Discontinued operations loss	0.7	0.2
Loss (gain) on sale of assets[2]	-	0.7
Adjusted EBITDA attributable to Murphy (Non-GAAP)	**414.4**	**465.8**

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.

(Millions of dollars)	Three Months Ended – Dec 31, 2023	Three Months Ended – Dec 31, 2022
EBITDAX attributable to Murphy (Non-GAAP)[1]	457.1	552.7
Accretion of asset retirement obligations[2]	10.6	10.2
Asset retirement obligation losses	16.9	30.8
Foreign exchange loss (gain)	11.1	5.7
Mark-to-market (gain) loss on contingent consideration	-	(20.2)
Mark-to-market (gain) on derivative instruments	-	(76.0)
Discontinued operations loss	0.7	0.2
Loss (gain) on sale of assets[2]	-	0.7
Adjusted EBITDAX attributable to Murphy (Non-GAAP)	**496.4**	**504.1**

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

AECO: Alberta Energy Company, the Canadian benchmark price for natural gas

BBL: Barrels (equal to 42 US gallons)

BCF: Billion cubic feet

BCFE: Billion cubic feet equivalent

BN: Billions

BOE: Barrels of oil equivalent (1 barrel of oil or 6,000 cubic feet of natural gas)

BOEPD: Barrels of oil equivalent per day

BOPD: Barrels of oil per day

CAGR: Compound annual growth rate

D&C: Drilling and completions

DD&A: Depreciation, depletion and amortization

EBITDA: Income from continuing operations before taxes, depreciation, depletion and amortization, and net interest expense

EBITDAX: Income from continuing operations before taxes, depreciation, depletion and amortization, net interest expense, and exploration expenses

EFS: Eagle Ford Shale

EUR: Estimated ultimate recovery

F&D: Finding and development

G&A: General and administrative expenses

GOM: Gulf of Mexico

IP: Initial production rate

LOE: Lease operating expense

MBO: Thousands barrels of oil

MBOE: Thousands barrels of oil equivalent

MBOEPD: Thousands of barrels of oil equivalent per day

MBOPD: Thousands of barrels of oil per day

MCF: Thousands of cubic feet

MCFD: Thousands cubic feet per day

MM: Millions

MMBOE: Millions of barrels of oil equivalent

MMCF: Millions of cubic feet

MMCFD: Millions of cubic feet per day

NGL: Natural gas liquids

ROR: Rate of return

R/P: Ratio of reserves to annual production

TCF: Trillion cubic feet

WI: Working interest

WTI: West Texas Intermediate (a grade of crude oil)

1Q 2024 Guidance

Producing Asset	Oil (BOPD)	NGLs (BOPD)	Gas (MCFD)	Total (BOEPD)
US – Eagle Ford Shale	19,400	4,400	24,400	27,900
– Gulf of Mexico excluding NCI[1]	59,500	4,700	56,500	73,600
Canada – Tupper Montney	–	–	327,100	54,500
– Kaybob Duvernay and Placid Montney	2,000	400	7,000	3,600
– Offshore	7,200	–	–	7,200
Other	200	–	–	200

1Q Production Volume (BOEPD) *excl. NCI* [1]	163,000 – 171,000
1Q Exploration Expense ($MM)	$24
Full Year 2024 CAPEX ($MM) *excl. NCI* [2]	$920 – $1,020
Full Year 2024 Production Volume (BOEPD) *excl. NCI* [3]	180,000 – 188,000

1 Excludes noncontrolling interest of MP GOM of 6,300 BOPD oil, 300 BOPD NGLs and 2,500 MCFD gas
2 Excludes noncontrolling interest of MP GOM of $22 MM
3 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

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

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

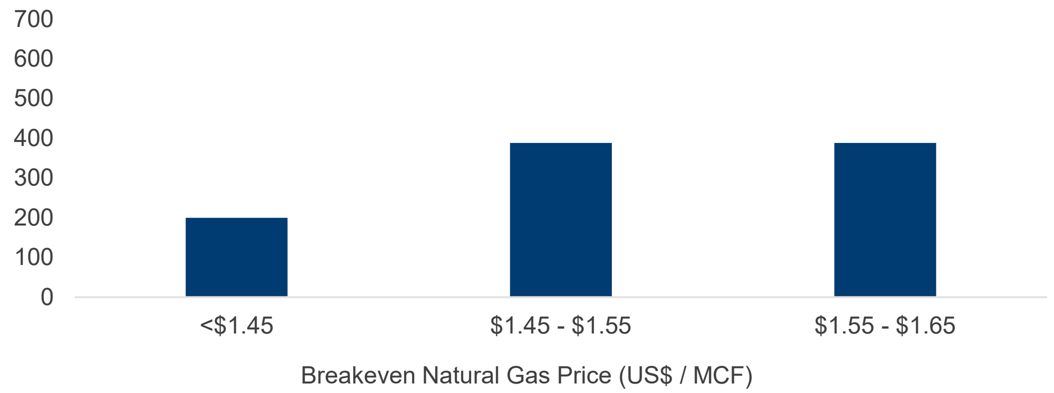
> 25 years of inventory < $50 / BBL
~ 55 years of total inventory
>15 years of Eagle Ford Shale inventory < $50 / BBL

Tupper Montney

~ 50 years of inventory

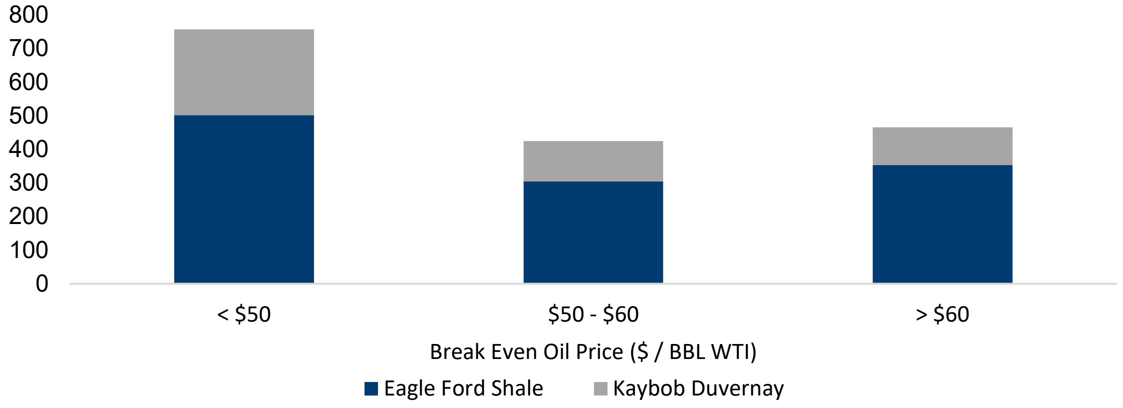
Tupper Montney – Natural Gas

Remaining Locations



Eagle Ford Shale and Kaybob Duvernay – Oil

Remaining Locations



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.

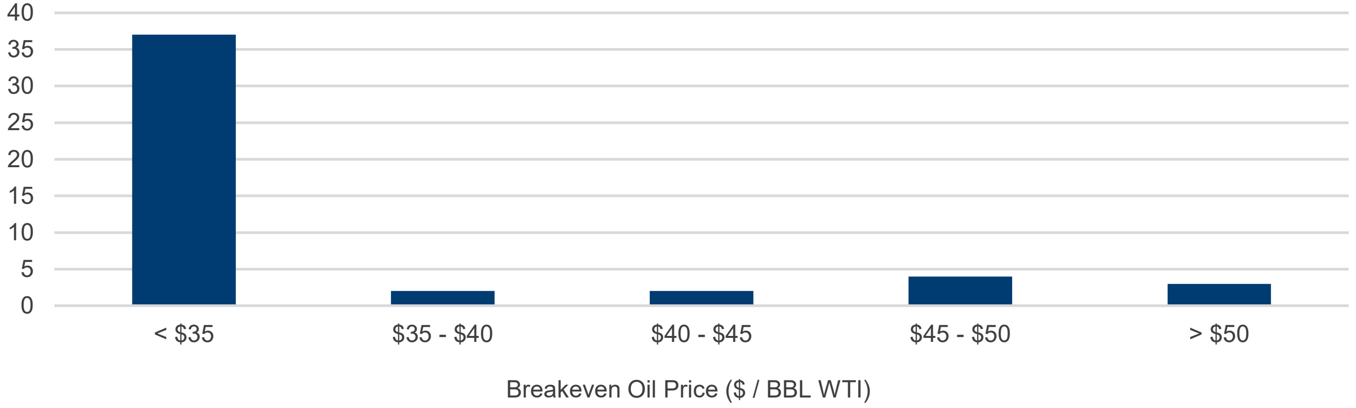
Offshore Development Opportunities

Multi-Year Inventory of High-Return Projects

Diversified, Low Breakeven Opportunities in Offshore Portfolio

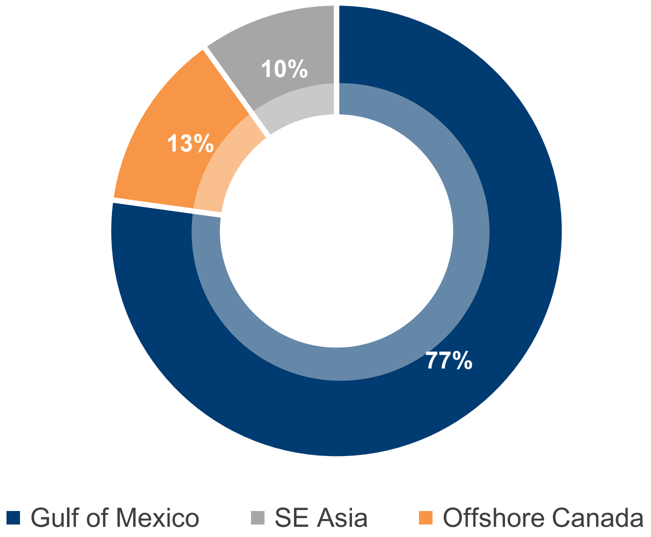
- Multi-year inventory of identified offshore projects in current portfolio
- Maintaining annual offshore production of 90 – 100 MBOEPD
  with average annual CAPEX of ~$380 MM from FY 2024 – FY 2028
- Projects include
  - 37 projects – 209 MMBOE of total resources with < $35 / BBL WTI breakeven
  - 8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

Identified Offshore Project Portfolio *Number of Projects*



Identified Offshore Project Portfolio

Percent MMBOE by Area



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

Tupper Montney Well Locations

Area	Net Acres	Inter-Well Spacing *(ft)*	Gross Remaining Locations
Tupper Montney	118,235	984 - 1,323	976

Eagle Ford Shale Operated Well Locations

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

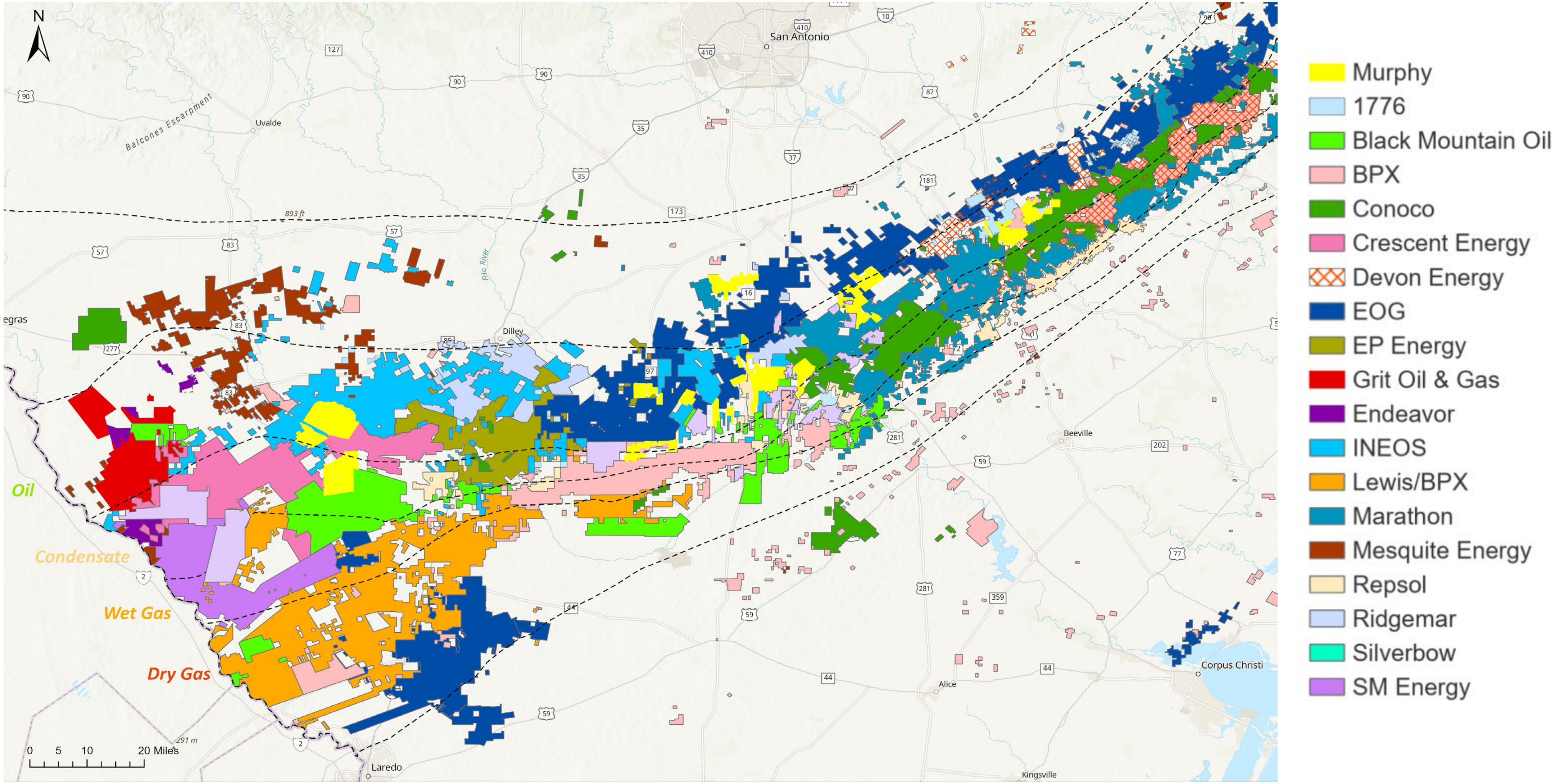
Kaybob Duvernay Well Locations

Area	Net Acres	Inter-Well Spacing *(ft)*	Gross Remaining Locations
Two Creeks	28,064	984	120
Kaybob East	32,825	984	152
Kaybob West	26,192	984	103
Kaybob North	23,604	984	113
Total	**110,685**		**488**

As of December 31, 2023

Eagle Ford Shale

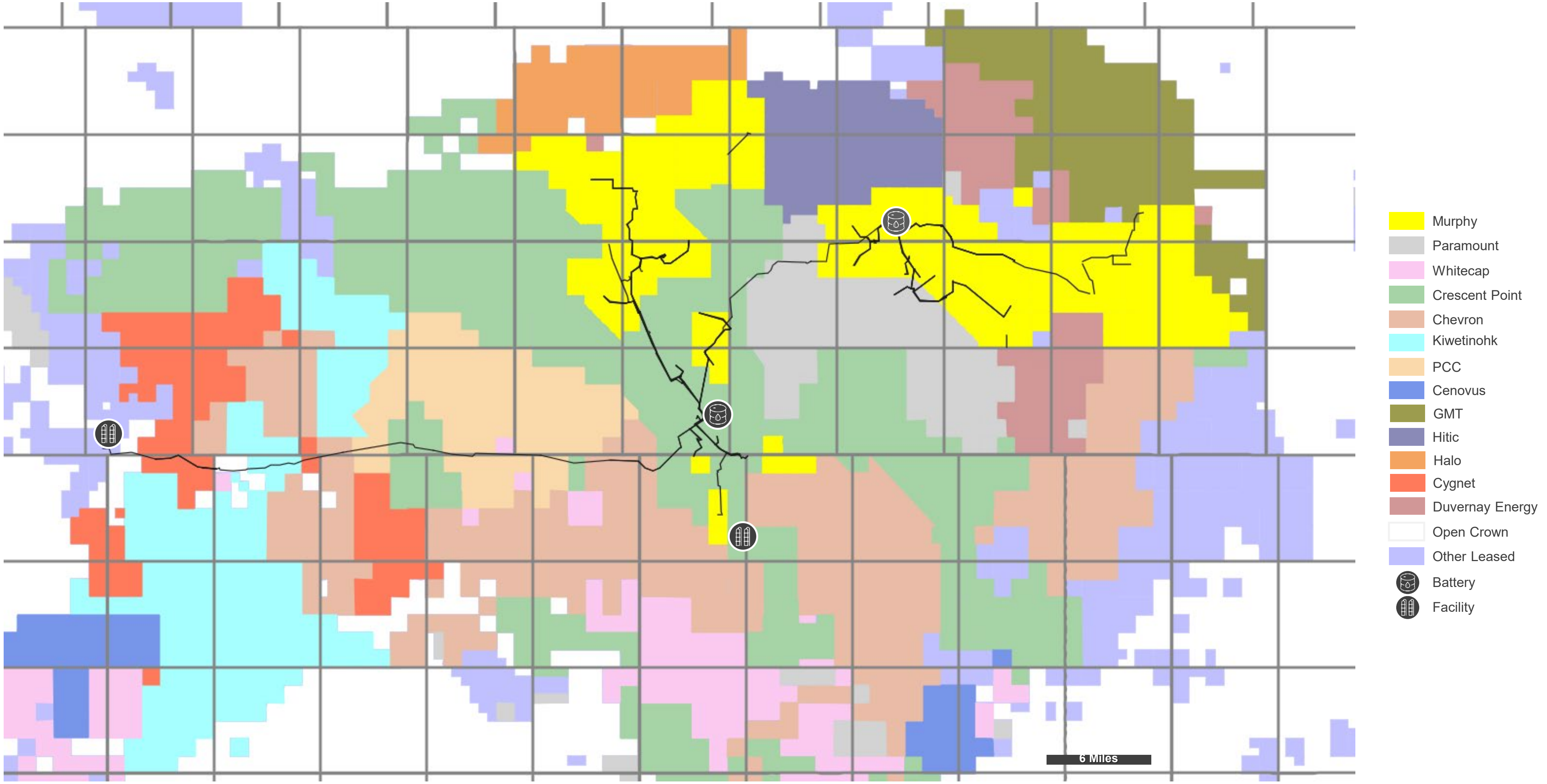
Peer Acreage



Acreage as of January 23, 2024

Kaybob Duvernay

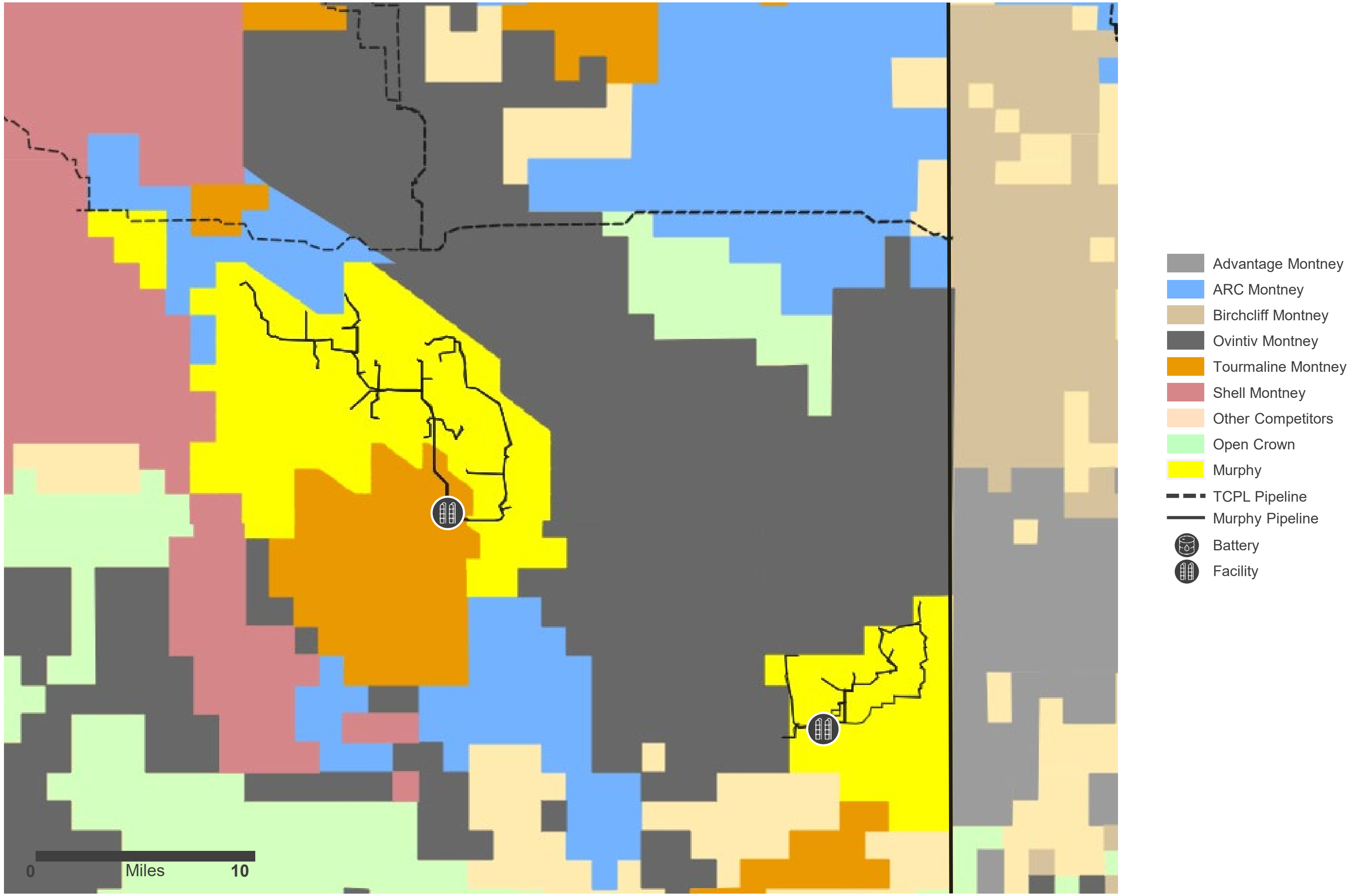
Peer Acreage



Acreage as of January 23, 2024

Tupper Montney

Peer Acreage



Acreage as of January 23, 2024

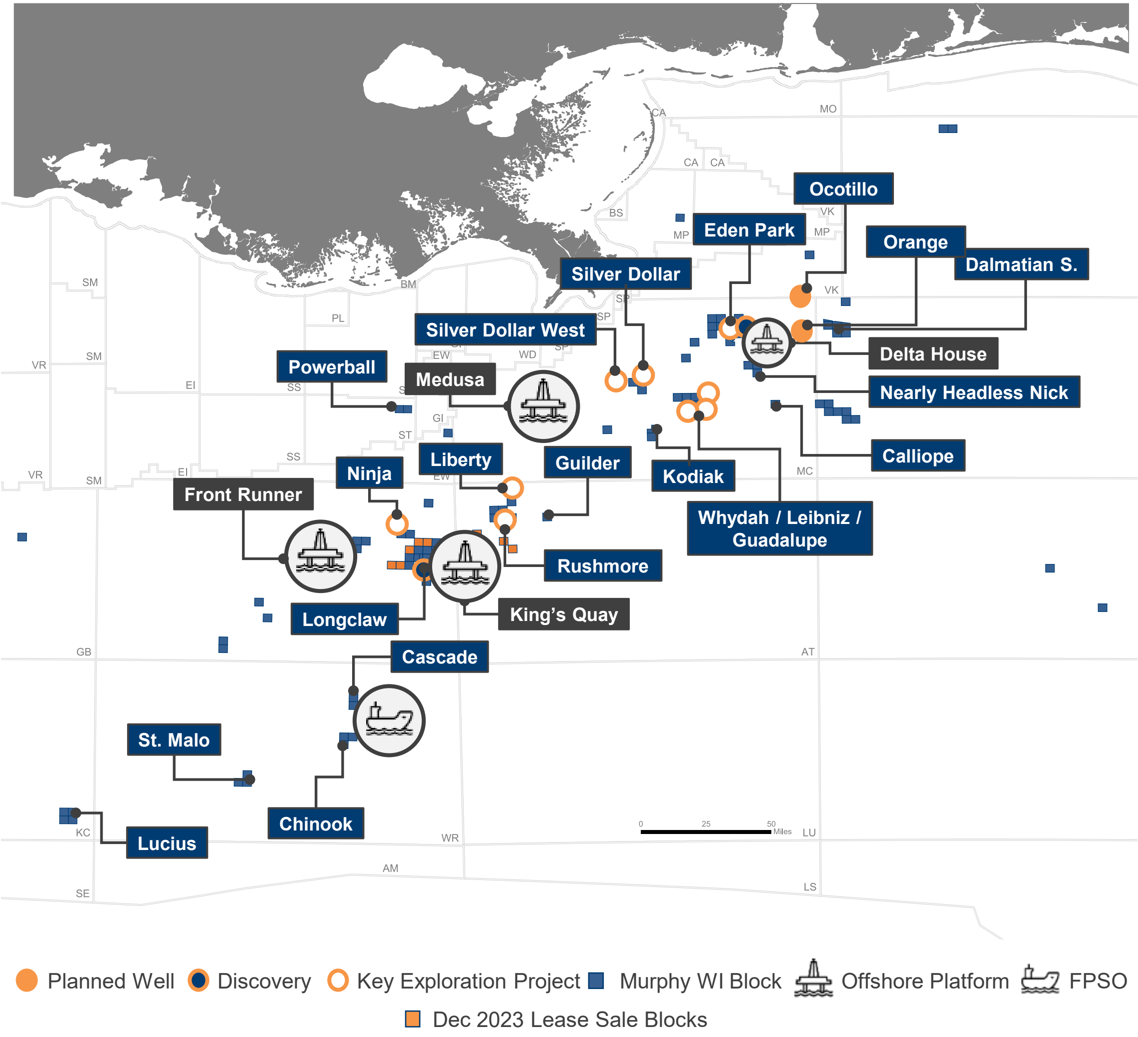
Gulf of Mexico

Murphy Blocks

PRODUCING ASSETS		
Asset	**Operator**	**Murphy WI[1]**
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[2]	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%

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

Gulf of Mexico Assets

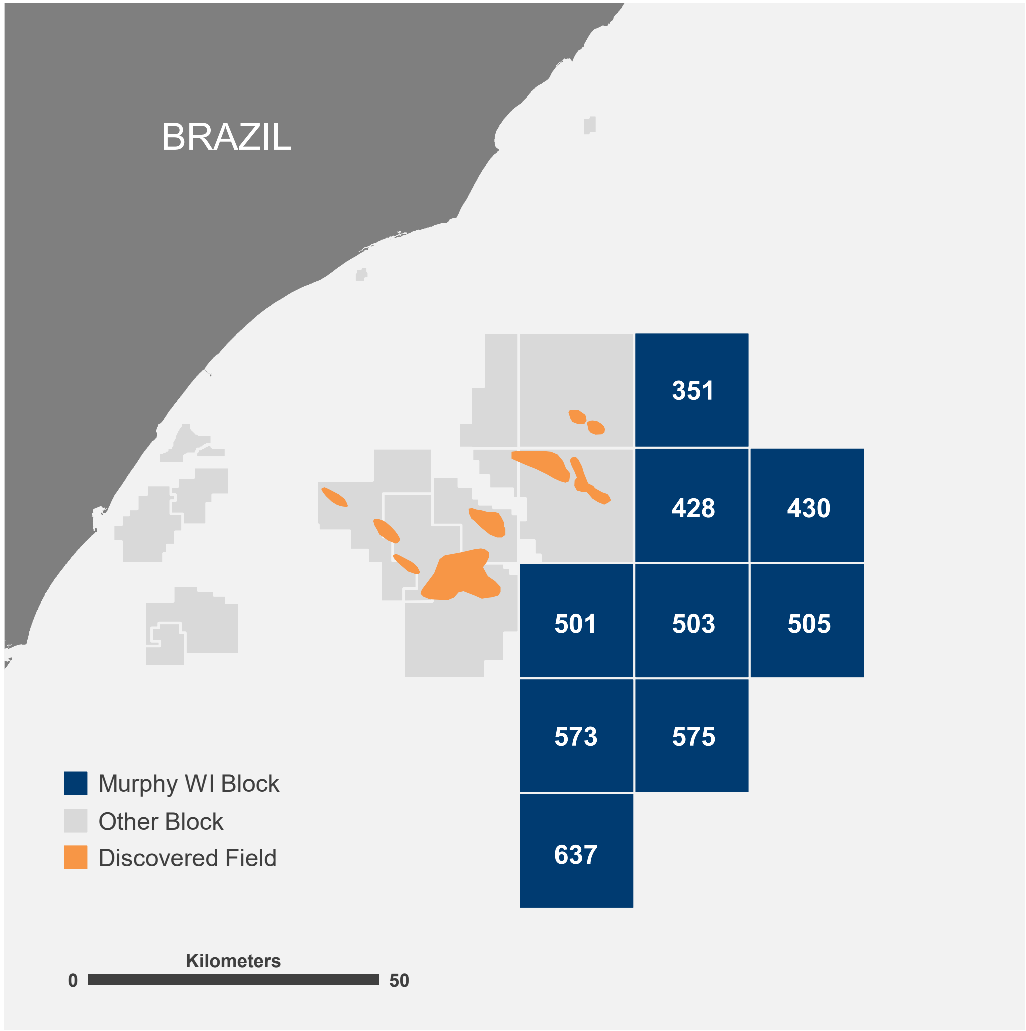


Exploration Update
Sergipe-Alagoas Basin, Brazil

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

Sergipe-Alagoas Basin



Acreage as of January 23, 2024

All blocks begin with SEAL-M

Exploration Update

Potiguar Basin, Brazil

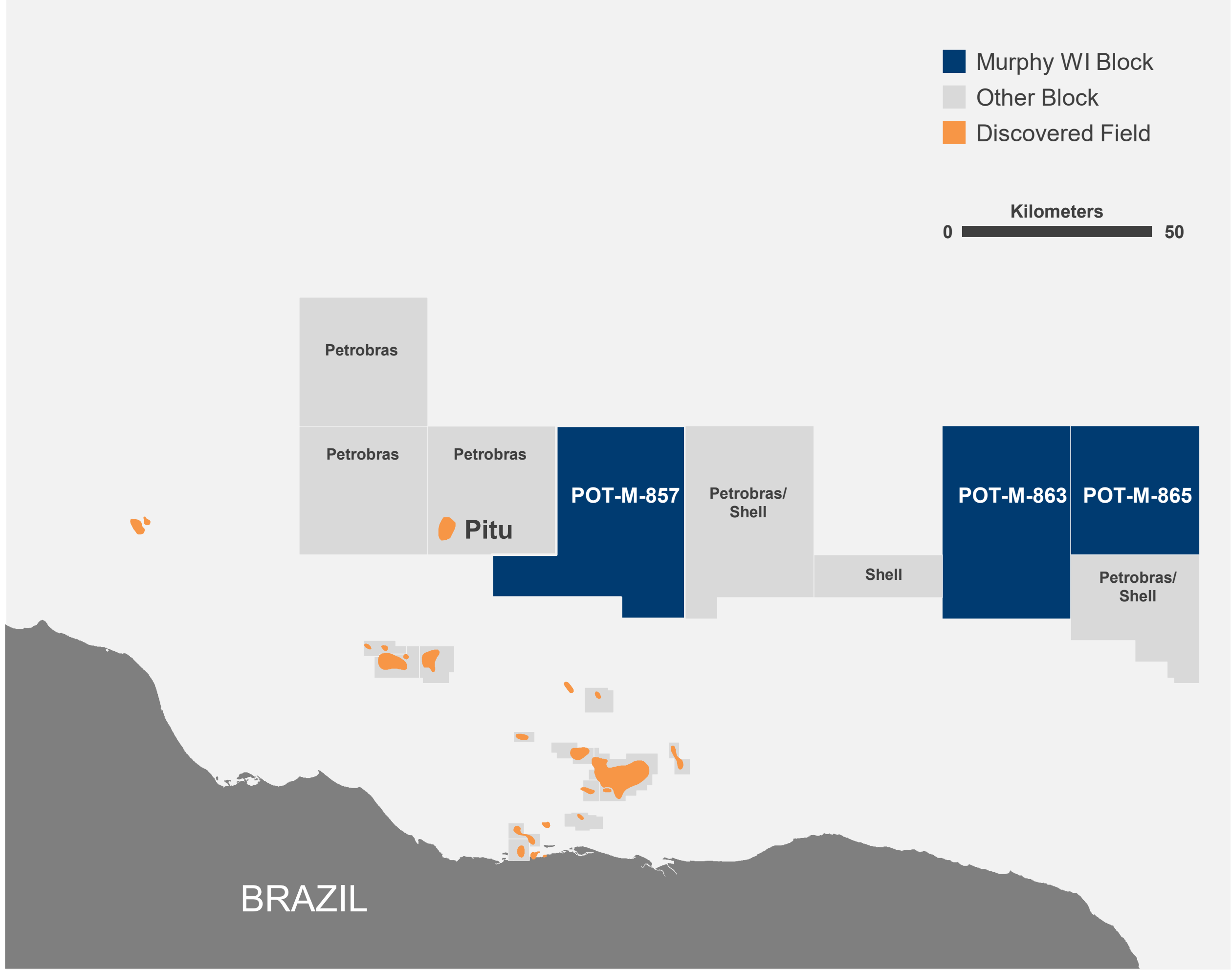
Asset Overview

- 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

Potiguar Basin



Acreage as of January 23, 2024

MURPHY
OIL CORPORATION

2023
FOURTH QUARTER EARNINGS

CONFERENCE CALL & WEBCAST

JANUARY 25, 2024

ROGER W. JENKINS

PRESIDENT & CHIEF EXECUTIVE OFFICER

FUTURE

performance | progress | people