MURPHY OIL CORPORATION

# 2021 FIRST QUARTER EARNINGS

## CONFERENCE CALL & WEBCAST

MAY 6, 2021

ROGER W. JENKINS

PRESIDENT & CHIEF EXECUTIVE OFFICER

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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.

Forward-Looking Statements – 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 or results, are subject to inherent risks and uncertainties. Factors that could cause one or more of these future events or results not to occur as implied by any forward-looking statement include, but are not limited to: macro conditions in the oil and natural gas industry, including supply/demand levels, actions taken by major oil exporters and the resulting impacts on commodity prices; 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 US or global capital markets, credit markets or economies in general. 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 US 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. 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.

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# Why Murphy Oil?

- Oil and natural gas assets that are safely operated with low carbon emissions intensity in three operating areas across North America
- High-potential exploration portfolio with industry-leading offshore capabilities
- Strong generator of free cash flow with capital allocation flexibility
- Financial discipline has led to 60-year track record of returning capital to shareholders
- Supported by multi-decade founding family, with meaningful board and management ownership

# Our 2021 Priorities

## DELEVER

- Achieved debt reduction of 8%, or ~$230 MM, in 1Q 2021
- Goal of further ~$200 MM in 2021, for total of ~15% reduction FY 2021 at current strip prices

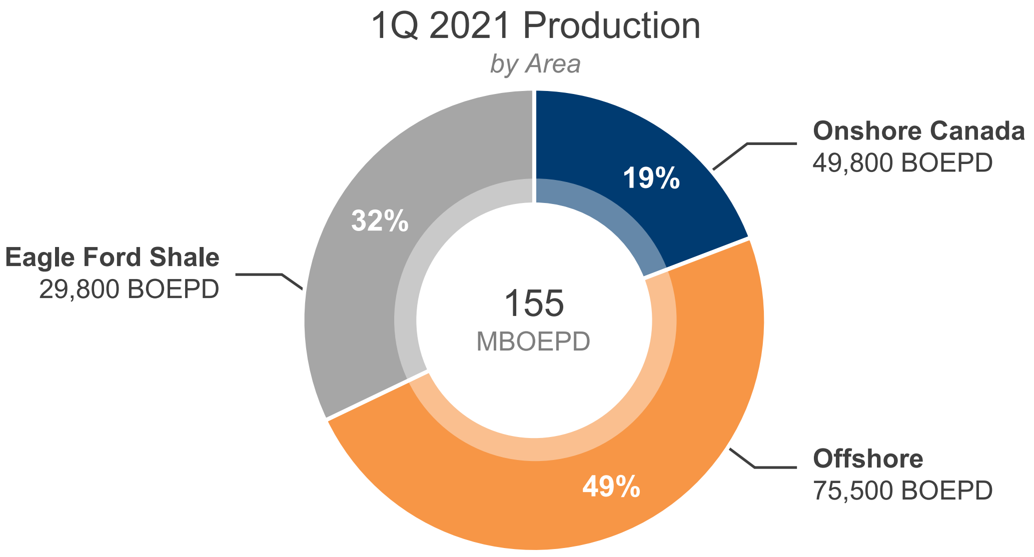
## EXECUTE

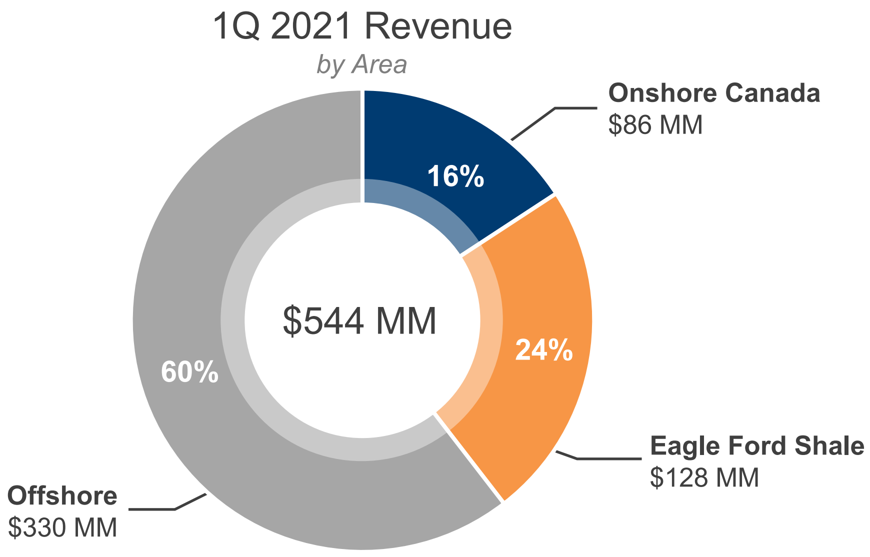
- Brought onshore wells online ahead of schedule and under budget
- Produced 88 MBOPD oil, or 7% above guide, with Eagle Ford Shale 4% above despite winter storm impact
- Remain on schedule for major offshore projects

## EXPLORE

- Spud Silverback exploration well in Gulf of Mexico in 2Q 2021
- Cutthroat exploration well in Brazil planned to spud in 3Q 2021

# 1Q 2021
## Production, Pricing and Revenue Update




### 1Q 2021 Production 155 MBOEPD, 63% Liquids

- 88 MBOPD oil production, beat oil guide of 82 MBOPD
- 1Q 2021 accrued CAPEX of $230 MM
  - Includes $20 MM cost of Lucius WI acquisition
  - Excludes King’s Quay spending of $17 MM and NCI CAPEX of $4 MM

### 1Q 2021 Pricing

- $58.04 / BBL realized oil price
- $2.55 / MCF realized natural gas price

*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*

# 1Q 2021 Financial Results

## 1Q 2021 Results

- Net loss $287 MM; adjusted net income $10 MM

## 1Q 2021 Adjustments

- Significant one-off income adjustments after-tax include:
  - Non-cash impairment of assets $128 MM
  - MTM non-cash loss on crude oil derivative contracts $121 MM
  - Early redemption of debt cost $29 MM

## Cash Flow from Continuing Operations

- Includes adjustment for non-cash long-term compensation of $12 MM

## Other Highlights

- 1Q 2021 accrued CAPEX of $230 MM, excluding NCI and King's Quay
  - Includes $20 MM cost of Lucius WI acquisition
- Added fixed price forward sales contracts related to Tupper Montney asset to underpin cash flow in FY 2021-2024

| **1Q 2021** *($MM Except Per Share)* | |
|---|---|
| **Net Income Attributable to Murphy** | |
| Income (loss) | ($287) |
| $/Diluted share | ($1.87) |
| **Adjusted Income from Cont. Ops.** | |
| Adjusted income (loss) | $10 |
| $/Diluted share | $0.06 |

| **Cash Flow Attributable to Murphy** *($MM)* | **1Q 2021** |
|---|---|
| Net cash provided by continuing operations | $238 |
| Property additions and dry hole costs* | ($258) |
| Proceeds from asset sales | $268 |
| **Adjusted Cash Flow** | **$248** |

| **Adjusted EBITDA Attributable to Murphy** *($MM)* | **1Q 2021** |
|---|---|
| EBITDA attributable to Murphy | ($99) |
| Impairment of assets | $171 |
| Mark-to-market (gain) loss on crude oil derivatives contracts and contingent consideration | $168 |
| Other | $15 |
| **Adjusted EBITDA** | **$255** |

*Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated*
*Free cash flow includes NCI*
** Includes King's Quay cash CAPEX of $18 MM and Lucius WI acquisition of $20 MM*

# Capital Execution and Guidance

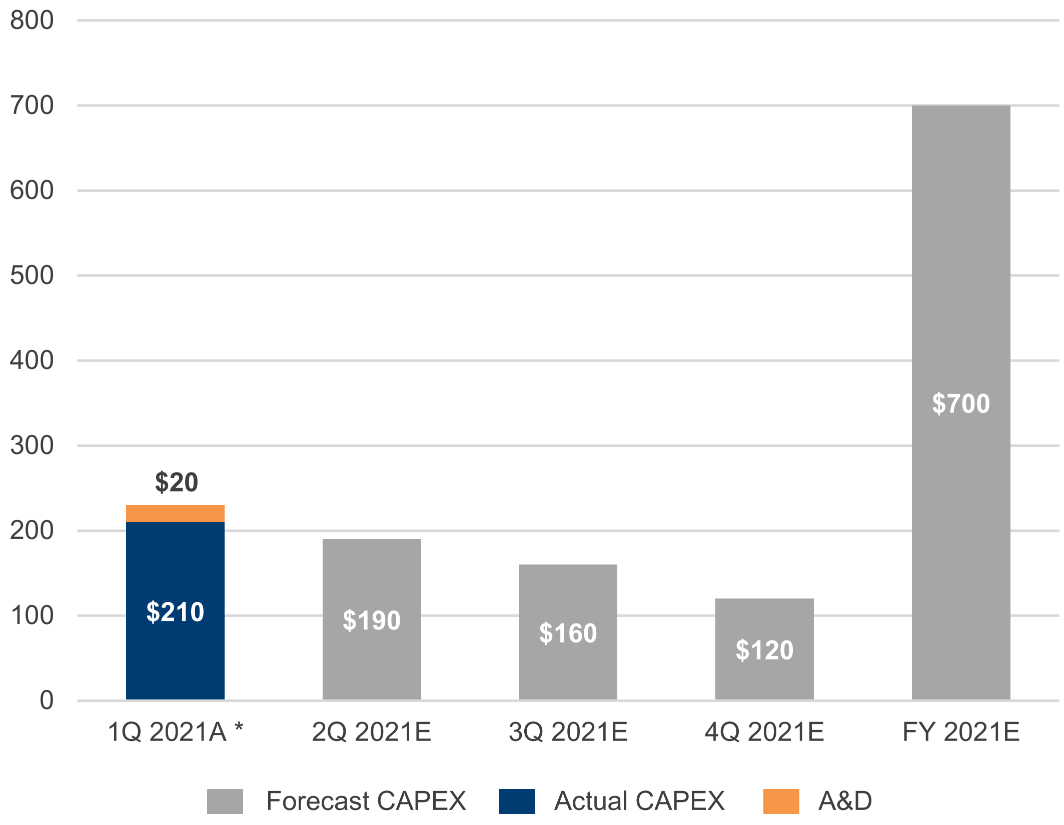
## Executing In-Line With Plan

- 1Q 2021 accrued CAPEX* of $230 MM aligned with plan
    - Includes $20 MM cost of Lucius WI acquisition
- Primary business units' CAPEX heavily weighted to 1Q 2021
    - Eagle Ford Shale 44% of FY 2021 plan
    - Gulf of Mexico 38% of FY 2021 plan
    - Onshore Canada 35% of FY 2021 plan

## Outperformance Leads to Production Guidance Raise

- Improved drilling technical performance while reducing costs
- Guiding 2Q 2021 production of 160 – 168 MBOEPD, with midpoint of oil production at 95 MBOPD
- Tightening FY 2021 production guidance to 157 – 165 MBOEPD
    - Accounts for additional 1 MBOEPD of acquired Lucius production
    - Maintain FY 2021 CAPEX guide of $675 – $725 MM

Accrued CAPEX by Quarter *$MM*




*Accrual CAPEX, based on midpoint of guidance range and excluding noncontrolling interest*
** Excludes King's Quay CAPEX of $17 MM*

# 1Q 2021 Cash Flow Simplification

## Cash Flow Adjustments

- Total inflow of cash of $1,048 MM
  - From operations, King's Quay monetization and senior notes transactions
- Total outflow of $1,128 MM
  - From transactions, dividends and distribution to NCI
  - Includes $20 MM cost of Lucius WI acquisition and $233 MM of net debt reduction
- Resulted in $80 MM cash deficit for the quarter, funded with cash on hand
  - $231 MM cash and equivalents as of March 31, 2021
- At current prices, goal of repurchasing additional ~$200 MM of senior notes in 2021

| Cash Flow Attributable to Murphy *($MM)* | Inflow | Outflow | Net |
|---|---|---|---|
| Cash from operations and property additions [1] | $238 | ($241) | ($3) |
| King's Quay monetization | $268 | ($218) [2] | $50 |
| Senior notes transactions | $542 | ($610) [3] | ($68) |
| Dividends | | ($19) | ($19) |
| Distribution to noncontrolling interest | | ($36) | ($36) |
| Other | | ($4) | ($4) |
| **Net Cash Flow** | **$1,048** | **($1,128)** | **($80)** |

*1 Includes noncontrolling interest*
*2 Includes 1Q 2021 CAPEX of $18 MM plus revolver payoff of $200 MM*
*3 Includes 2022 notes principal amount of $576 MM plus $34 MM early redemption of debt cost*

# ONSHORE PORTFOLIO UPDATE

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with Sustainable Solutions

# North America Onshore

## Balancing Investments for Free Cash Generation to Delever Balance Sheet

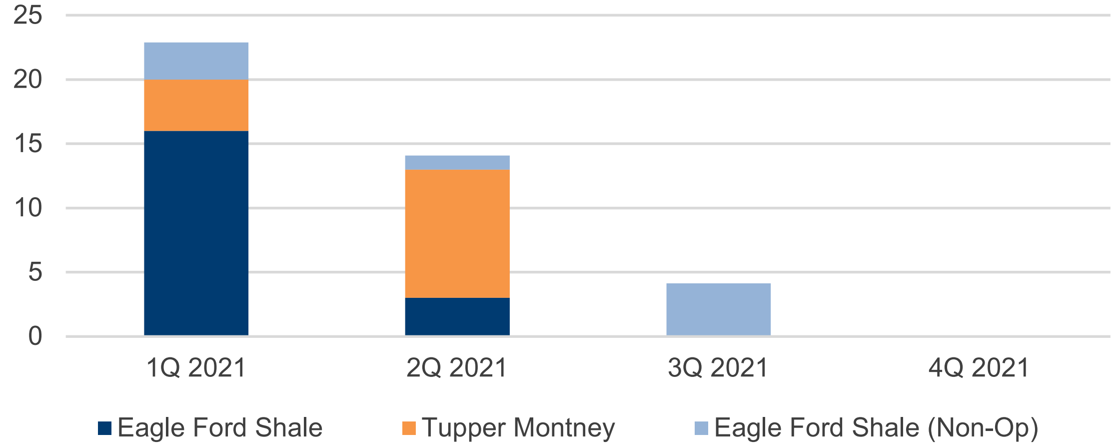
### 1Q 2021 Onshore Activity

- Eagle Ford Shale
  - 16 operated wells + 16 gross non-operated wells* online
  - $75 MM of $170 MM FY 2021 CAPEX guidance
    - 19 operated + 45 gross non-operated wells online
- Tupper Montney
  - 4 operated wells online
  - 5 wells accelerated into 2Q 2021
  - $30 MM of $85 MM FY 2021 CAPEX guidance
    - 14 operated wells online

### Reducing Environmental Impact and Costs

- Displaced ~1 MM gal of diesel with clean-burning natural gas in D&C operations
  - ~$1.3 MM cost savings across North America onshore
- Utilized 800 MBBLs of recycled water in completions
  - ~$3 MM in disposal cost savings
- Electrification of third-party processing plant in Tupper Montney, resulting in lower emissions

2021 Wells Online




*Note: Non-op well cadence subject to change per operator plans*
** Eagle Ford Shale non-operated wells adjusted for 18% average working interest*

# Eagle Ford Shale

## Base Production Outperforms While Lowering Costs

### 1Q 2021 30 MBOEPD, 74% Oil, 88% Liquids

- 2.2 MBOEPD impact from Feb freeze
- 16 operated wells online, all Karnes
    - Primarily Lower EFS and Austin Chalk
    - Avg 1,400 BOEPD IP30
    - Two best wells achieved 2,000 BOEPD IP30

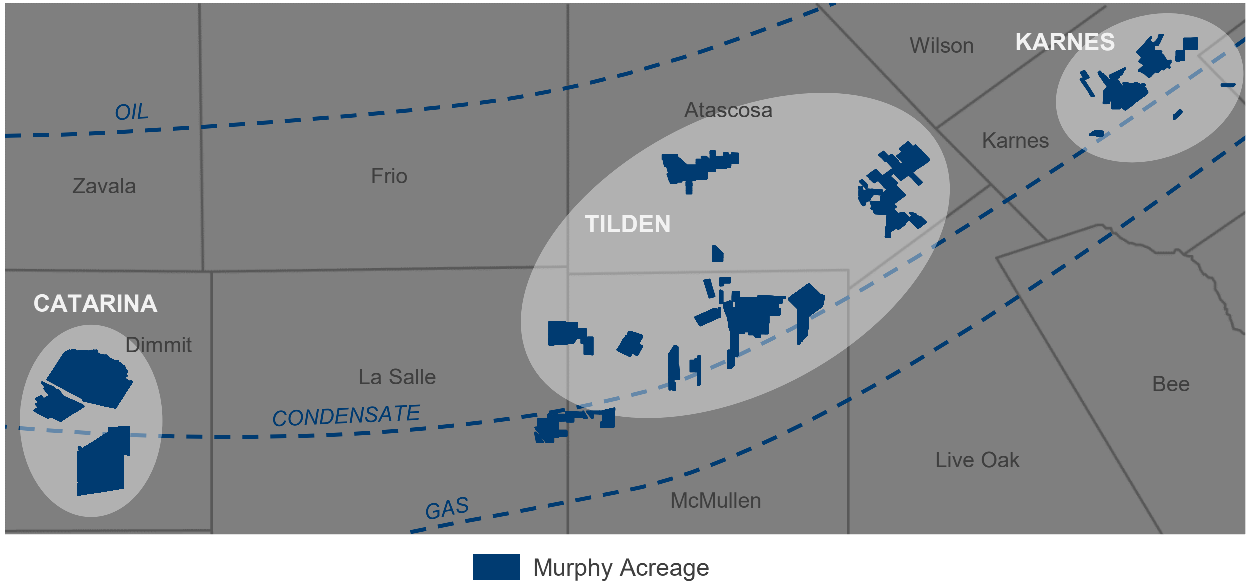
### Lowering D&C Costs

- 40% reduction in completions costs since FY 2018
- ~$4.5 MM avg well cost in 1Q 2021, down from ~$6.3 MM in FY 2018
- Karnes avg cost per well in-line with top peers

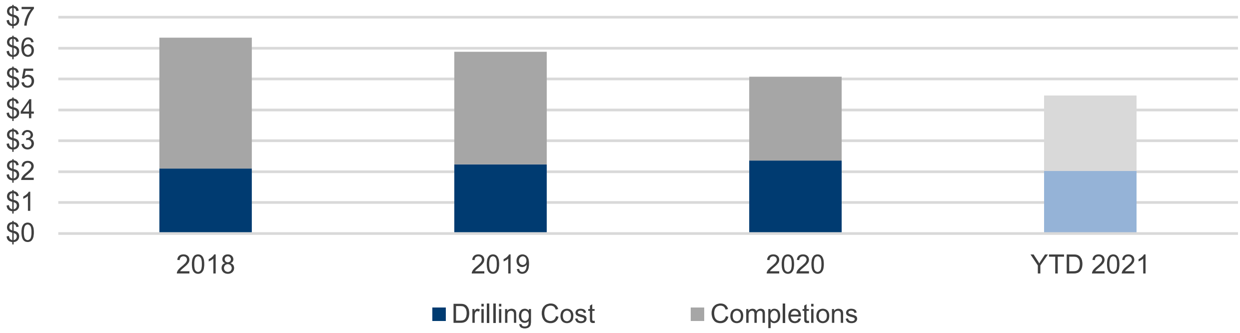
### Achieving Strong Austin Chalk Results

- 1Q 2021 Karnes Tier 2 wells meaningfully outperforming Tier 1 type curve
    - Avg 1,400 BOEPD IP30 rate
- Reassessing ultimate recovery expectations based on results
    - ~100 Karnes locations as of YE 2020

Eagle Ford Shale Acreage




Eagle Ford Shale Drilling and Completions *$MM per well*



### 1Q 2021 234 MMCFD, 100% Natural Gas

- 4 wells online, 45 days ahead of plan
- Lowering D&C costs
  - ~$4.1 MM avg well cost in 1Q 2021, down from ~$5.5 MM in FY 2019
  - 28% reduction since FY 2017
- Mechanical problem at 1 well and increased royalties impacted production

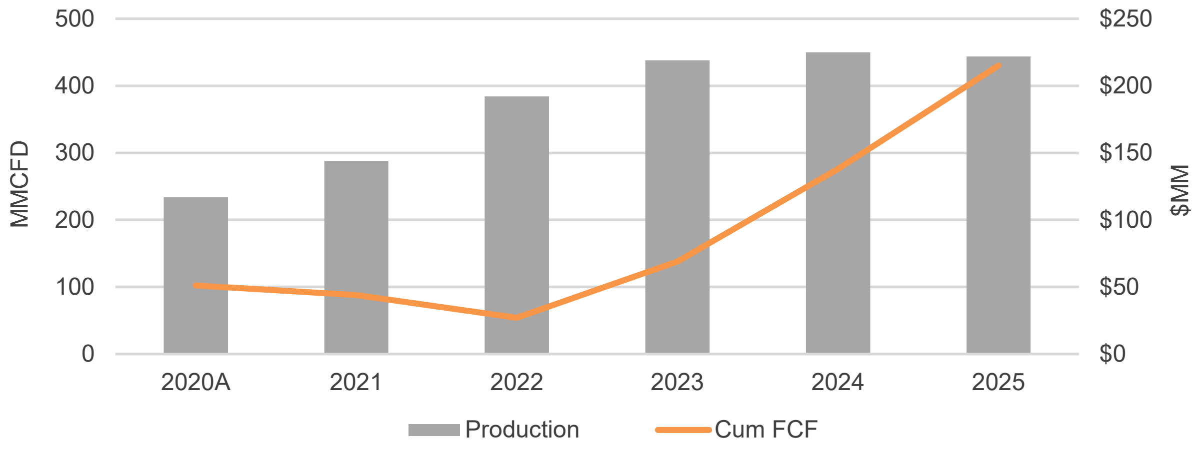
### ~1,400 Remaining Locations* Support a Low-Carbon Energy Future

### Low Execution Risk

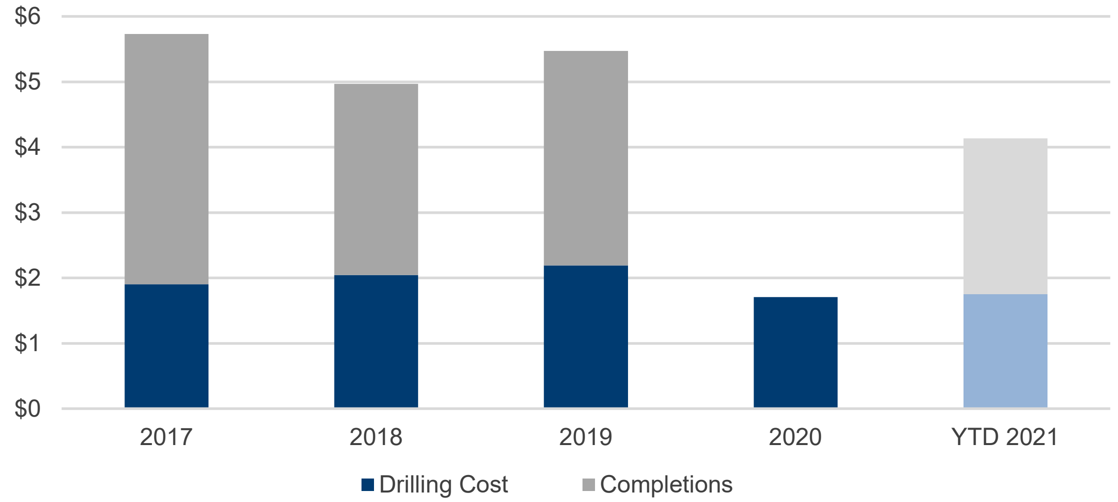
- Average ultimate recovery of ~21 BCF / well
- Low subsurface risk from proven resource
- Ample existing take-away and infrastructure in place

** Includes contingent well count*

Tupper Montney Production and Cumulative FCF




Tupper Montney Drilling and Completions *$MM per well*



# OFFSHORE PORTFOLIO UPDATE

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Leaning Into Challenges
with Sustainable Solutions

# Gulf of Mexico

## Major Projects Drive Future Free Cash Flow

### Khaleesi / Mormont / Samurai

- Launched drilling campaign 2Q 2021
  - Drilled top hole sections for 3 wells
  - Currently drilling Samurai #3 well
- On track for first oil in 1H 2022

### St. Malo Waterflood

- First producer well online
- Drilling final well of 4-well campaign in 2Q 2021

Facilities

| Project Components | Fabrication | Commissioning | Installation / Hook-up |
|---|---|---|---|
| King's Quay FPS | ✓ | 3Q 2021 – 2Q 2022 | 1H 2022 |
| King's Quay Moorings | ✓ | N/A | 2Q 2021 / 4Q 2021 |
| Subsea Flowlines and Equipment | Ongoing | 1H 2022 | 4Q 2021 – 3Q 2022 |

Drilling and Completions

| Field | Drilled | Completions | Online |
|---|---|---|---|
| Khaleesi | ✓ ✓ ● | 4Q 2021 | 1H 2022 |
| Mormont | ✓ ✓ | 1Q 2022 | 1H 2022 |
| Samurai | ✓ ● | 2Q 2022 | 2H 2022 |

● Planned well ✓ Drilling in progress ✓ Drilled well

*See Appendix for major project CAPEX and production cadence*

## King’s Quay Floating Production System

- Monetization closed 1Q 2021 for $268 MM of proceeds
- Completed construction in 2Q 2021
- Sail away to Gulf of Mexico on track for 3Q 2021
- On track to receive first oil 1H 2022

King’s Quay – Platform Crane Installation

# EXPLORATION UPDATE

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# 2021 Exploration Plan

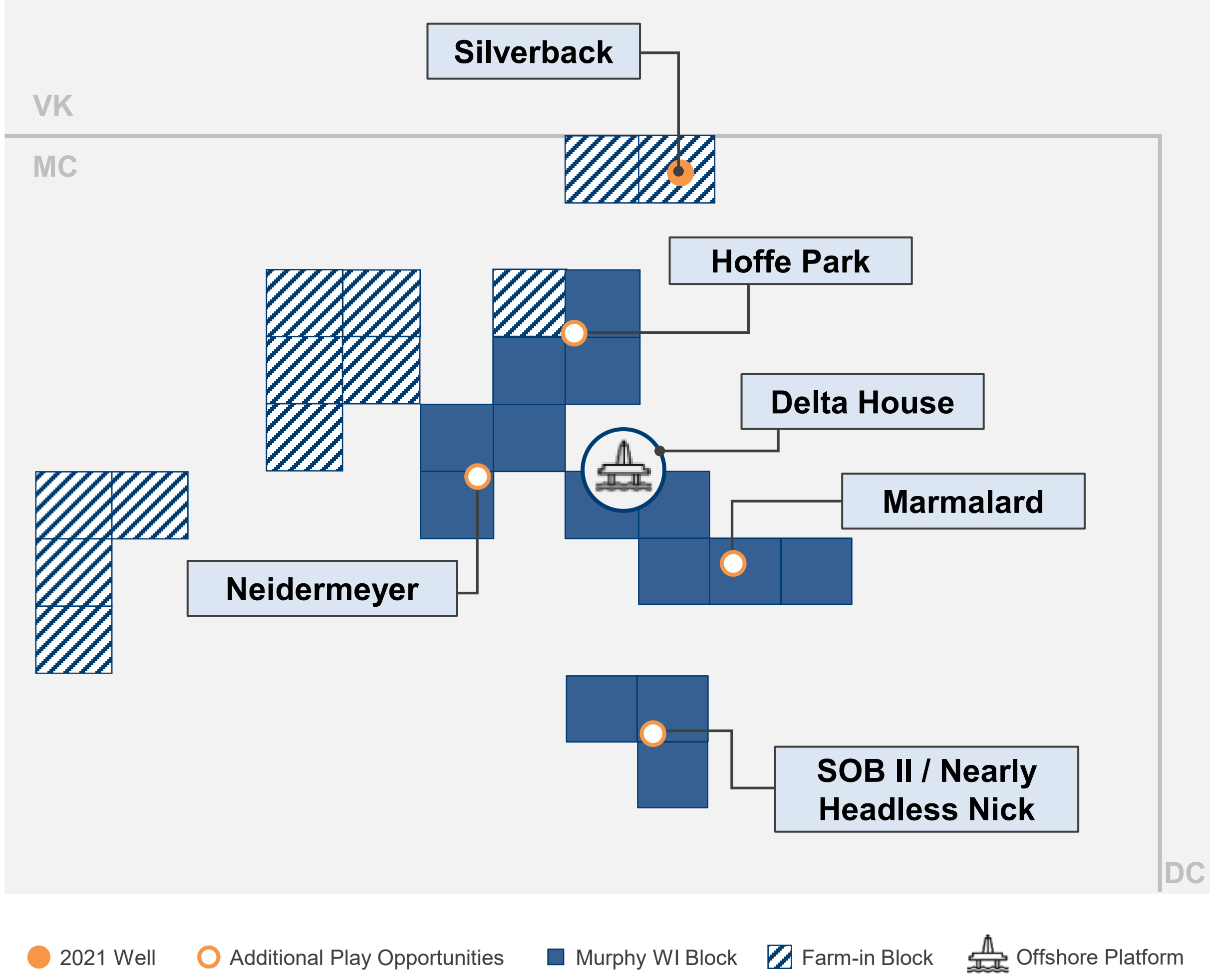
## Gulf of Mexico – Mississippi Canyon 35

### Asset Overview

- Chevron 80% (Op), Murphy 10%, Ecopetrol 10%
- Acreage is adjacent to large position held by Murphy and partners
  - Additional play opportunities
- Farm-in results in access to 12 blocks via Silverback well participation

### Silverback #1 (Mississippi Canyon 35)

- Targeting attractive, play-opening trend
- Spud 2Q 2021



# 2021 Exploration Plan
## Sergipe-Alagoas Basin, Brazil

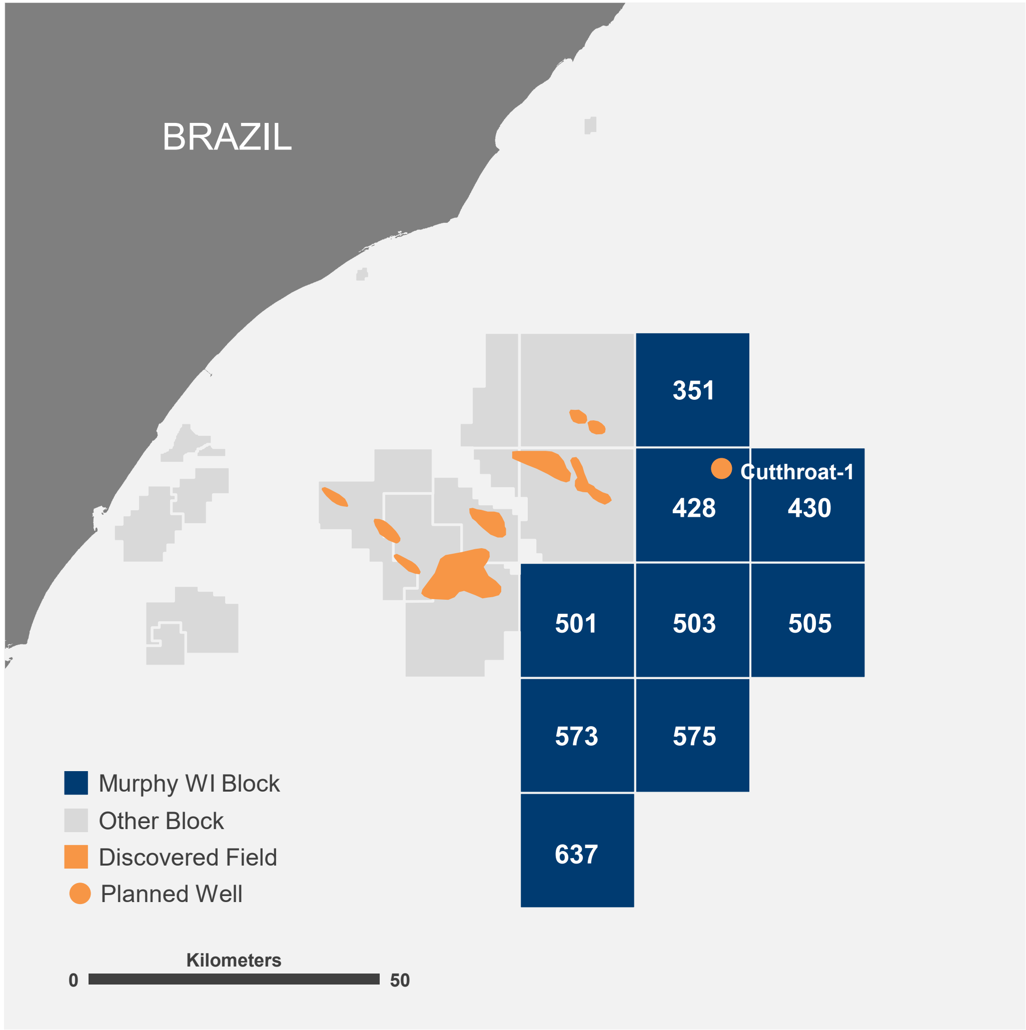
### Asset Overview

- ExxonMobil 50% (Op), Enauta Energia S.A. 30%, Murphy 20%
- Hold WI in 9 blocks, spanning >1.6 MM acres
- >2.8 BN BOE discovered in basin
- >1.2 BN BOE in deepwater since 2007
- Material opportunities identified on Murphy WI blocks

### Drilling Program

- On track for drilling Cutthroat-1 in 2H 2021
  - ~$15 MM net cost
- Mean to upward gross resource potential
  - 500 MMBOE – 1,050 MMBOE
- Continuing to mature inventory and plan future well timing

Sergipe-Alagoas Basin




*All blocks begin with SEAL-M*

# LOOKING AHEAD

# Disciplined Strategy Leads to Long-Term Value

## Delever, Execute, Explore
2021 – 2024

Achieve < $1.4 BN debt by 2024*

Spend annual average CAPEX of ~$600 MM

Deliver production CAGR of ~6% in 2021 – 2024

Produce consistent oil-weighting, ~50% in 2021 – 2024

Maintain offshore production average of ~75 MBOEPD in 2021 – 2024

Advance exploration portfolio of > 1 BBOE net risked potential resources

Pay consistent dividend to shareholders

## Capital Allocation Optionality

Reduce debt further

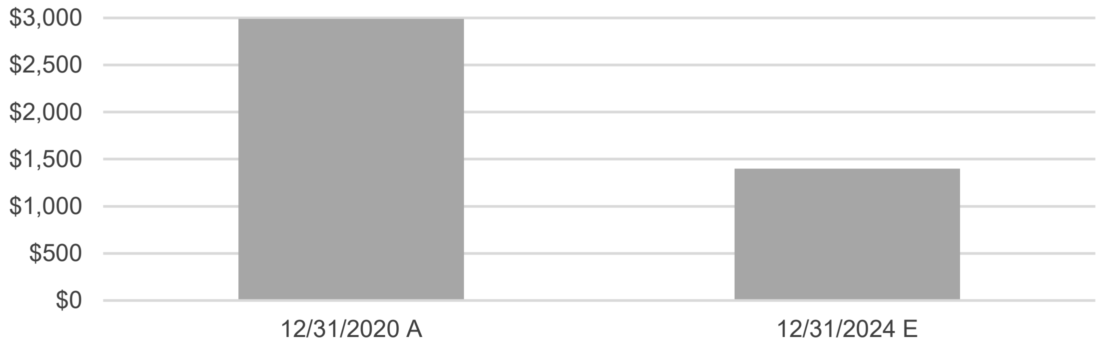
Allocate additional capital to assets

Fund exploration success

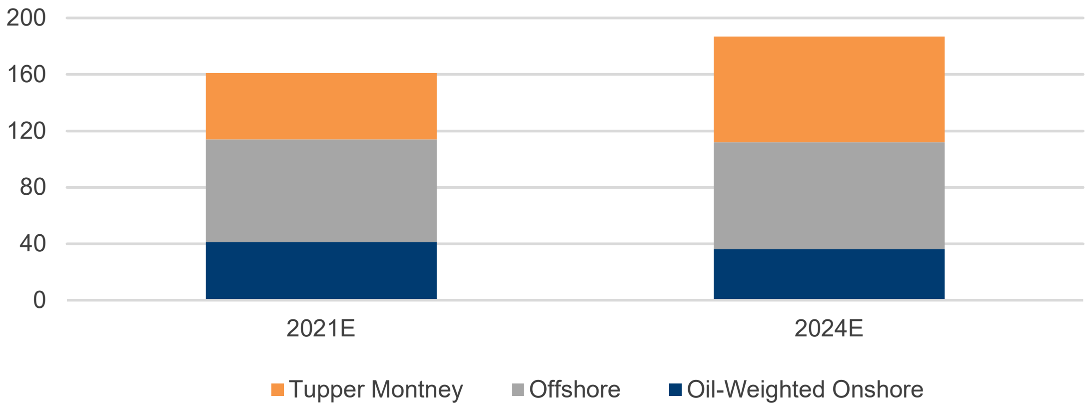
Evaluate strategic A&D opportunities

Return additional cash to shareholders

Forecast Debt Outstanding *$MMs*




2021E – 2024E Production *MBOEPD*




** Assumes long-term $60 WTI oil price*

*Note: Oil-weighted onshore includes Eagle Ford Shale and Kaybob Duvernay*

# Focused on Targeted Priorities

## DELEVER

- Goal of further ~$200 MM, for total of ~15% reduction in FY 2021 at current strip prices
- Plan allows for debt reduction to ~$1.4 BN by FYE 2024 from FYE 2020, with potential for further reductions long-term

## EXECUTE

- Progress major projects in the Gulf of Mexico ahead of first oil in 1H 2022
- Continue achieving drilling and completions cost efficiencies and lowering emissions intensity
- Maintain strong safety and environmental metrics

## EXPLORE

- Focus on drilling 2 non-op wells in Gulf of Mexico and Brazil in 2021
- Progress on 2022 exploration plans with partners

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# 2021
# FIRST QUARTER EARNINGS

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# Appendix

1. Non-GAAP Definitions and Reconciliations
2. Glossary of Abbreviations
3. 2Q 2021 Guidance
4. Current Hedging Positions
5. Supplemental Information
6. Acreage Maps

# 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

## EBITDA and EBITDAX

Murphy defines EBITDA as net income (loss) attributable to Murphy[1] before interest, taxes, depreciation and amortization (DD&A). Murphy defines EBITDAX as net income (loss) attributable to Murphy before interest, taxes, depreciation and amortization (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* | **Three Months Ended – Mar 31, 2021** | **Three Months Ended – Mar 31, 2020** |
|---|---|---|
| Net (loss) income attributable to Murphy (GAAP) | (287.4) | (416.1) |
| Income tax (benefit) expense | (88.2) | (91.5) |
| Interest expense, net | 88.1 | 41.1 |
| DD&A expense | 188.3 | 286.2 |
| **EBITDA attributable to Murphy (Non-GAAP)** | **(99.2)** | **(180.3)** |
| Exploration expense | 11.8 | 20.1 |
| **EBITDAX attributable to Murphy (Non-GAAP)** | **(87.4)** | **(160.2)** |

*1 'Attributable to Murphy' represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.*

# Non-GAAP Reconciliation

## ADJUSTED EBITDA

Murphy defines Adjusted EBITDA as net income (loss) attributable to Murphy[1] before interest, taxes, depreciation and amortization (DD&A), impairment expense, discontinued operations, foreign exchange gains and losses, mark-to-market gains and losses on crude oil derivative contracts, 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, except per BOE amounts* | Three Months Ended – Mar 31, 2021 | Three Months Ended – Mar 31, 2020 |
|---|---|---|
| **EBITDA attributable to Murphy (Non-GAAP)** | (99.2) | (180.3) |
| Impairment of assets | 171.3 | 866.4 |
| Mark-to-market loss (gain) on crude oil derivative contracts | 153.5 | (358.3) |
| Mark-to-market loss (gain) on contingent consideration | 14.9 | (59.2) |
| Accretion of asset retirement obligations | 10.5 | 10.0 |
| Unutilized rig charges | 2.8 | 3.5 |
| Foreign exchange losses (gains) | 1.3 | (4.7) |
| Discontinued operations (income) loss | (0.2) | 4.9 |
| Inventory loss | - | 4.8 |
| **Adjusted EBITDA attributable to Murphy (Non-GAAP)** | **254.9** | **287.1** |
| Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels) | 13,670 | 17,071 |
| **Adjusted EBITDA per BOE (Non-GAAP)** | **18.65** | **16.82** |

*1 'Attributable to Murphy' represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.*

# Non-GAAP Reconciliation

## ADJUSTED EBITDAX

Murphy defines Adjusted EBITDAX as net income (loss) attributable to Murphy[1] before interest, taxes, depreciation and amortization (DD&A), exploration expense, impairment expense, discontinued operations, foreign exchange gains and losses, mark-to-market gains and losses on crude oil derivative contracts, 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, except per BOE amounts* | Three Months Ended – Mar 31, 2021 | Three Months Ended – Mar 31, 2020 |
|---|---|---|
| **EBITDAX attributable to Murphy (Non-GAAP)** | (87.4) | (160.2) |
| Impairment of assets | 171.3 | 866.4 |
| Mark-to-market loss (gain) on crude oil derivative contracts | 153.5 | (358.3) |
| Mark-to-market loss (gain) on contingent consideration | 14.9 | (59.2) |
| Accretion of asset retirement obligations | 10.5 | 10.0 |
| Unutilized rig charges | 2.8 | 3.5 |
| Foreign exchange losses (gains) | 1.3 | (4.7) |
| Discontinued operations (income) loss | (0.2) | 4.9 |
| Inventory loss | - | 4.8 |
| **Adjusted EBITDAX attributable to Murphy (Non-GAAP)** | **266.7** | **307.2** |
| Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels) | 13,670 | 17,071 |
| **Adjusted EBITDAX per BOE (Non-GAAP)** | **19.51** | **17.99** |

*1 'Attributable to Murphy' represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.*

# Glossary of Abbreviations

**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 & completion

**DD&A:** Depreciation, depletion & 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 & development

**G&A:** General and administrative expenses

**GOM:** Gulf of Mexico

**LOE:** Lease operating expense

**MBOE:** Thousands barrels of oil equivalent

**MBOEPD:** Thousands of barrels of oil equivalent 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

**NA:** North America

**NGL:** Natural gas liquid

**ROR:** Rate of return

**R/P:** Ratio of reserves to annual production

**TCF:** Trillion cubic feet

**TCPL:** TransCanada Pipeline

**TOC:** Total organic content

**WI:** Working interest

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

# 2Q 2021 Guidance

| Producing Asset | Oil (BOPD) | NGLs (BOPD) | Gas (MCFD) | Total (BOEPD) |
|---|---|---|---|---|
| US – Eagle Ford Shale | 28,300 | 5,000 | 27,400 | 37,900 |
| – Gulf of Mexico excluding NCI[1] | 57,400 | 5,100 | 68,800 | 74,000 |
| Canada – Tupper Montney | – | – | 236,400 | 39,400 |
| – Kaybob Duvernay and Placid Montney | 5,400 | 1,000 | 18,200 | 9,400 |
| – Offshore | 3,300 | – | – | 3,300 |

| | |
|---|---|
| 2Q Production Volume (BOEPD) *excl. NCI* [1] | 160,000 – 168,000 |
| 2Q Exploration Expense ($MM) | $20 |
| Full Year 2021 CAPEX ($MM) *excl. NCI* [2] | $675 – $725 |
| Full Year 2021 Production Volume (BOEPD) *excl. NCI* [3] | 157,000 – 165,000 |

*1 Excludes noncontrolling interest of MP GOM of 9,500 BOPD oil, 600 BOPD NGLs and 4,600 MCFD gas*
*2 Excludes noncontrolling interest of MP GOM of $30 MM*
*3 Excludes noncontrolling interest of MP GOM of 8,800 BOPD oil, 500 BOPD NGLs and 4,300 MCFD gas*

# Current Hedging Positions

## United States

| Commodity | Type | Volumes (BBL/D) | Price (BBL) | Start Date | End Date |
|---|---|---|---|---|---|
| WTI | Fixed Price Derivative Swap | 45,000 | $42.77 | 4/1/2021 | 12/31/2021 |
| WTI | Fixed Price Derivative Swap | 20,000 | $44.88 | 1/1/2022 | 12/31/2022 |

## Montney, Canada

| Commodity | Type | Volumes (MMCF/D) | Price (MCF) | Start Date | End Date |
|---|---|---|---|---|---|
| Natural Gas | Fixed Price Forward Sales at AECO | 203 | C$2.55 | 4/1/2021 | 5/31/2021 |
| Natural Gas | Fixed Price Forward Sales at AECO | 241 | C$2.57 | 6/1/2021 | 12/31/2021 |
| Natural Gas | Fixed Price Forward Sales at AECO | 231 | C$2.42 | 1/1/2022 | 1/31/2022 |
| Natural Gas | Fixed Price Forward Sales at AECO | 221 | C$2.41 | 2/1/2022 | 4/30/2022 |
| Natural Gas | Fixed Price Forward Sales at AECO | 250 | C$2.40 | 5/1/2022 | 5/31/2022 |
| Natural Gas | Fixed Price Forward Sales at AECO | 292 | C$2.39 | 6/1/2022 | 12/31/2022 |
| Natural Gas | Fixed Price Forward Sales at AECO | 201 | C$2.36 | 1/1/2023 | 12/31/2023 |
| Natural Gas | Fixed Price Forward Sales at AECO | 147 | C$2.41 | 1/1/2024 | 12/31/2024 |

** As of May 5, 2020*

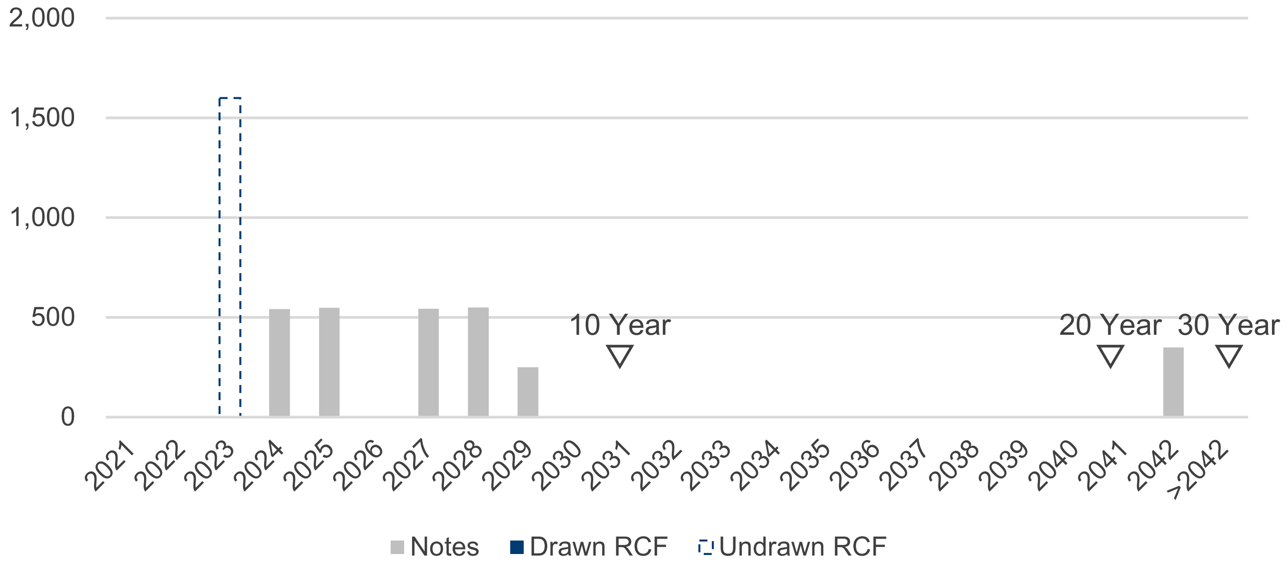
# Balance Sheet Stability

## Solid Foundation for Commodity Price Cycles

- $1.6 BN senior unsecured credit facility matures Nov 2023, undrawn at March 31, 2021
- All debt is unsecured, senior credit facility not subject to semi-annual borrowing base redeterminations
- $231 MM of cash and cash equivalents at March 31, 2021
- Next senior notes maturity due in 2024
- 41% total debt to cap, 39% net debt to cap

| Maturity Profile* | |
|---|---|
| Total Bonds Outstanding $BN | $2.756 |
| Weighted Avg Fixed Coupon | 6.3% |
| Weighted Avg Years to Maturity | 7.7 |

Note Maturity Profile *$MM*




** As of March 31, 2021*

# North America Onshore

## Eagle Ford Shale Operated Well Locations

| Area | Net Acres | Reservoir | Inter-Well Spacing *(ft)* | Remaining Wells |
|---|---|---|---|---|
| Karnes | 10,092 | Lower EFS | 300 | 106 |
| | | Upper EFS | 600 | 142 |
| | | Austin Chalk | 1,200 | 97 |
| Tilden | 64,770 | Lower EFS | 600 | 264 |
| | | Upper EFS | 500 | 138 |
| | | Austin Chalk | 600 | 100 |
| Catarina | 48,375 | Lower EFS | 550 | 238 |
| | | Upper EFS | 950 | 219 |
| | | Austin Chalk | 1,200 | 112 |
| **Total** | **123,237** | | | **1,416** |

**As of December 31, 2020*

## Kaybob Duvernay Well Locations

| Area | Net Acres | Inter-Well Spacing *(ft)* | Remaining Wells |
|---|---|---|---|
| Two Creeks | 35,232 | 984 | 104 |
| Kaybob East | 37,744 | 984 | 152 |
| Kaybob West | 25,984 | 984 | 107 |
| Kaybob North | 25,536 | 984 | 98 |
| Simonette | 32,116 | 984 | 108 |
| Saxon | 12,298 | 984 | 57 |
| **Total** | **168,910** | | **626** |

**As of December 31, 2020*

# Tupper Montney Project

## Low Carbon Intensity Development With Attractive Cash Margins

### Tupper Montney Advantages

- Employ capital allocation process that maximizes free long term cash flow
  - Generates greater cash margin per well than Eagle Ford Shale at conservative prices
  - < $1 / MCF average new well breakeven cost
- Long history of continuous improvement
  - Increasing laterals to ~11,000’
  - Improved drilling and completion costs to ~$5 MM / well
  - Increased average ultimate recovery to ~21 BCF / well

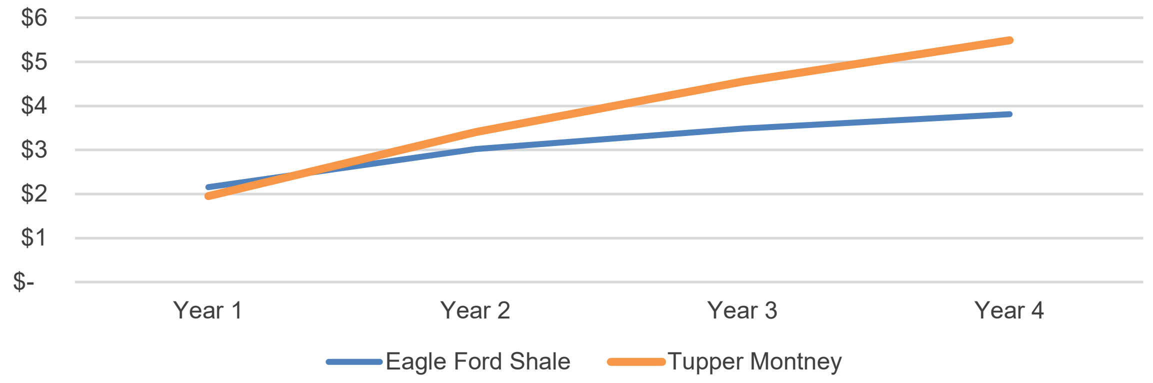
### Improved Macro Economics for Region

- Increased local take-away capacity and debottlenecking completed
  - 600 MMCFD westward export 2020 – 2022
  - 1.3 BCFD eastward export 2021 – 2022
- Declining regional production 2 BCFPD lower Y-o-Y
- Improved domestic demand due to coal to natural gas switching
- Construction underway for LNG Canada project, estimated in service in 2025
- Lowest AECO to Henry Hub basis differential in 5 years

### Low Carbon Intensity Asset

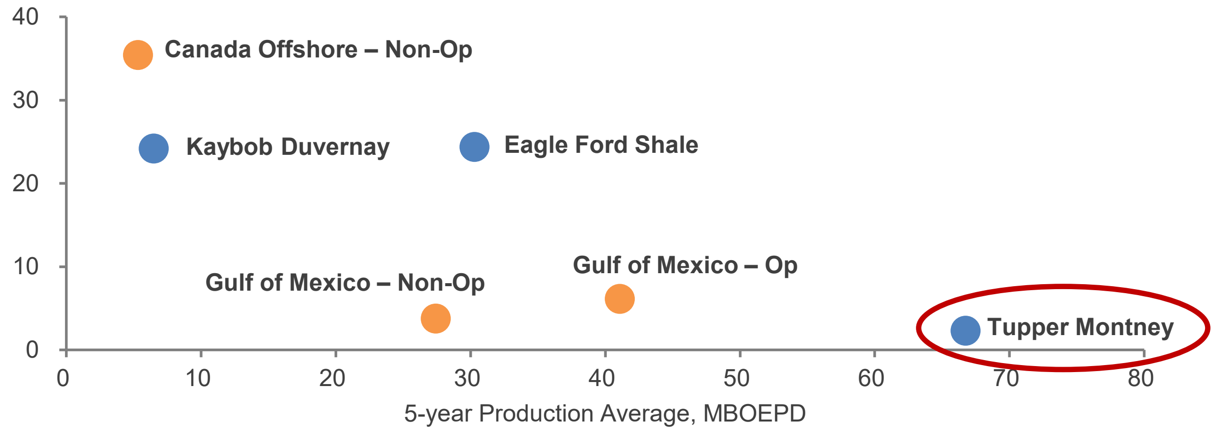
- Lowest greenhouse gas intensity asset in current portfolio

Annual Cumulative Cash Margin Per Well *$MM*




*Cash margins based on average price $44 / WTI, $1.78 / MCF AECO*

Average 5-Year GHG Intensity by Asset *Tonnes $CO_2e$ / MBOE*




*Note: 5-year average intensity based on internal estimates*

# Tupper Montney Development

## High Impact Development Drives Future Cash Flows

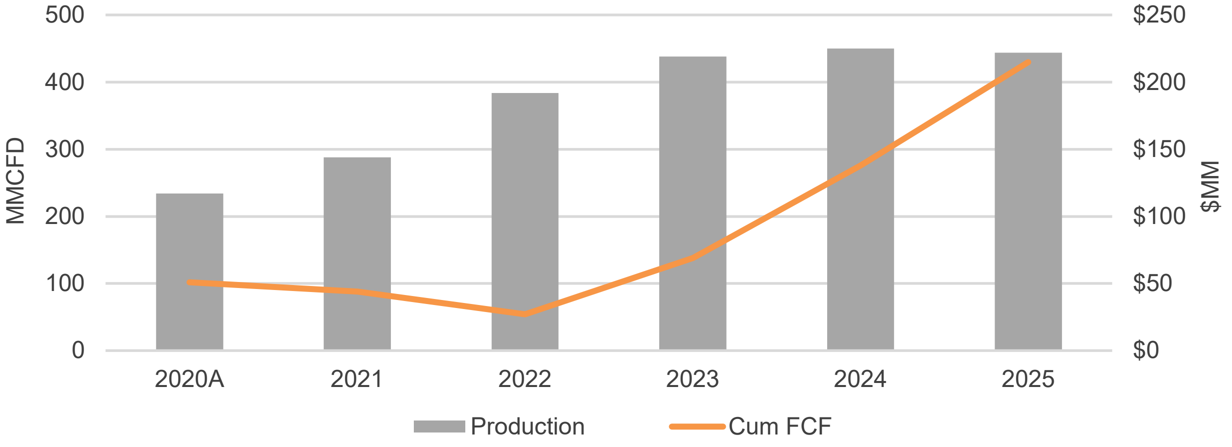
### Tupper Montney Development Plan

- Commitment to infrastructure approved 2Q 2018; sanctioned 4Q 2020
- Free cash flow generated in 2020 of ~$50 MM covers cumulative free cash flow requirement of $24 MM for 2021 – 2022
- Average annual capex of ~$68 MM from 2020 – 2025
- Cumulative free cash flow of ~$215 MM from 2020 – 2025

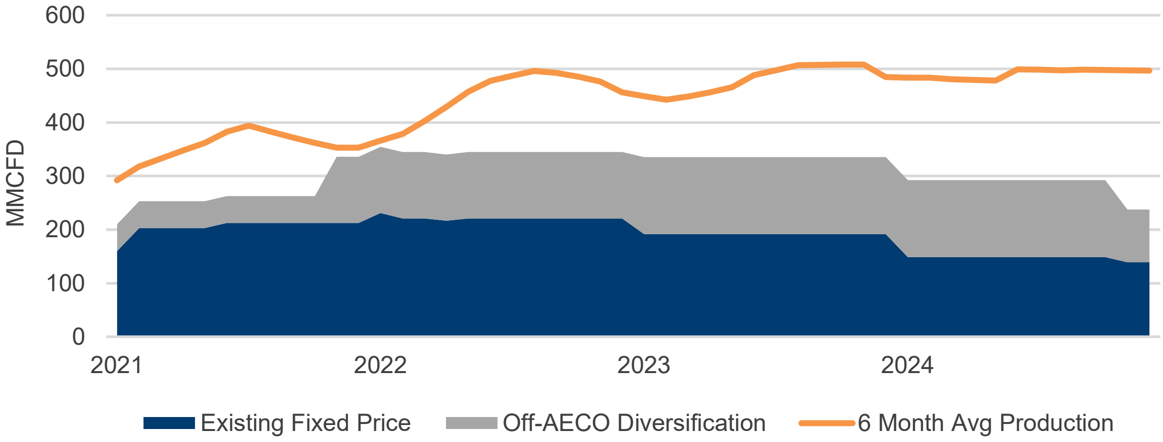
### Low Execution Risk

- Increased average ultimate recovery to ~21 BCF / well
- Low subsurface risk from proven resource
- Ample existing take-away and infrastructure in place
- Mitigate price risk with fixed price forward sales contracts through 2024

Tupper Montney Production and Cumulative FCF



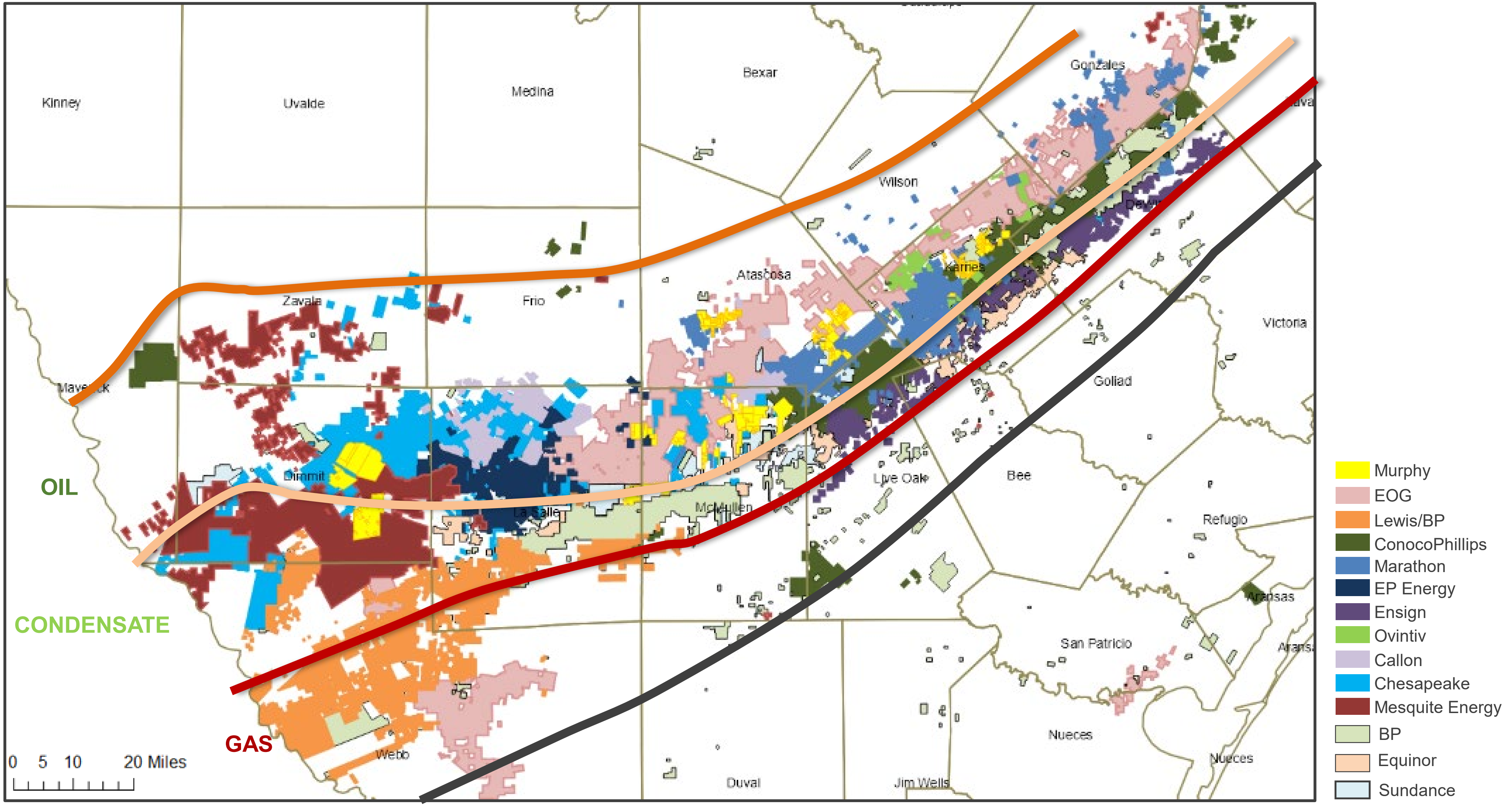

Tupper Montney Development Hedging and Production




*Note: Free cash flow = operating cash flow (-) CAPEX (-) abandonment*
*FCF based on average price $1.98/MCF hedged, $1.78/MCF AECO*
*Note: Future production volumes based on current sanctioned plan*

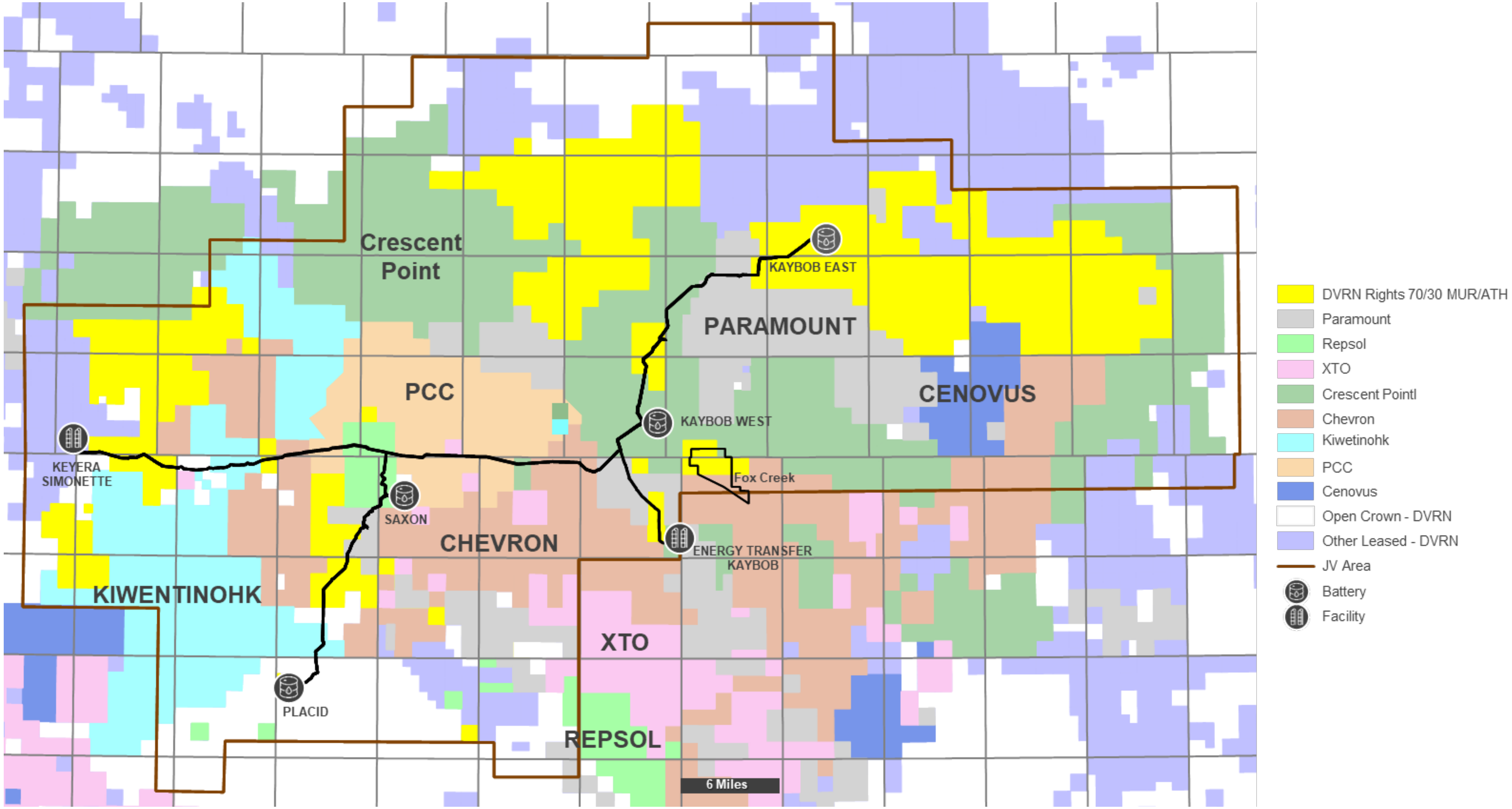
# Eagle Ford Shale

## Peer Acreage



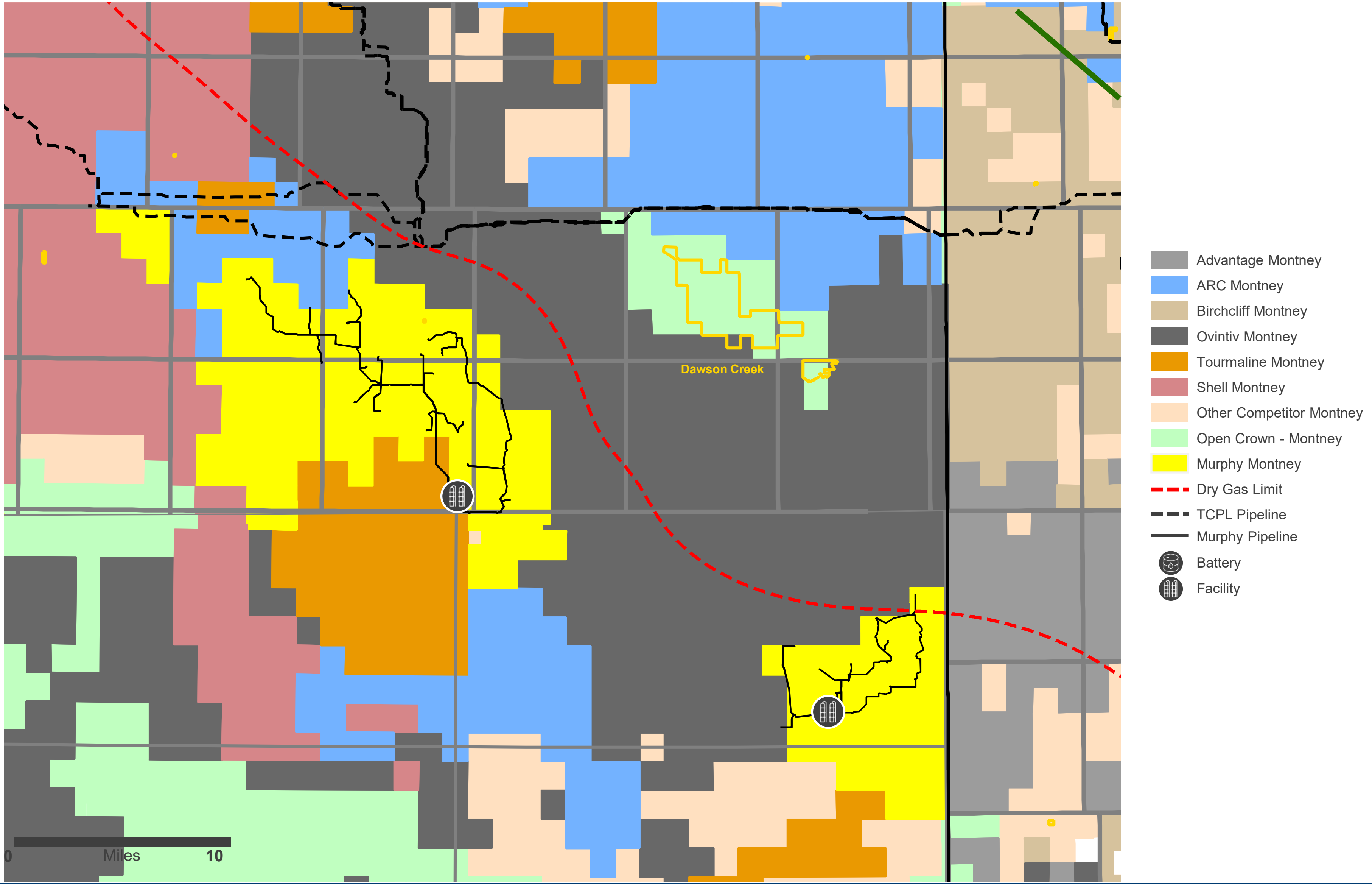
# Kaybob Duvernay

## Peer Acreage



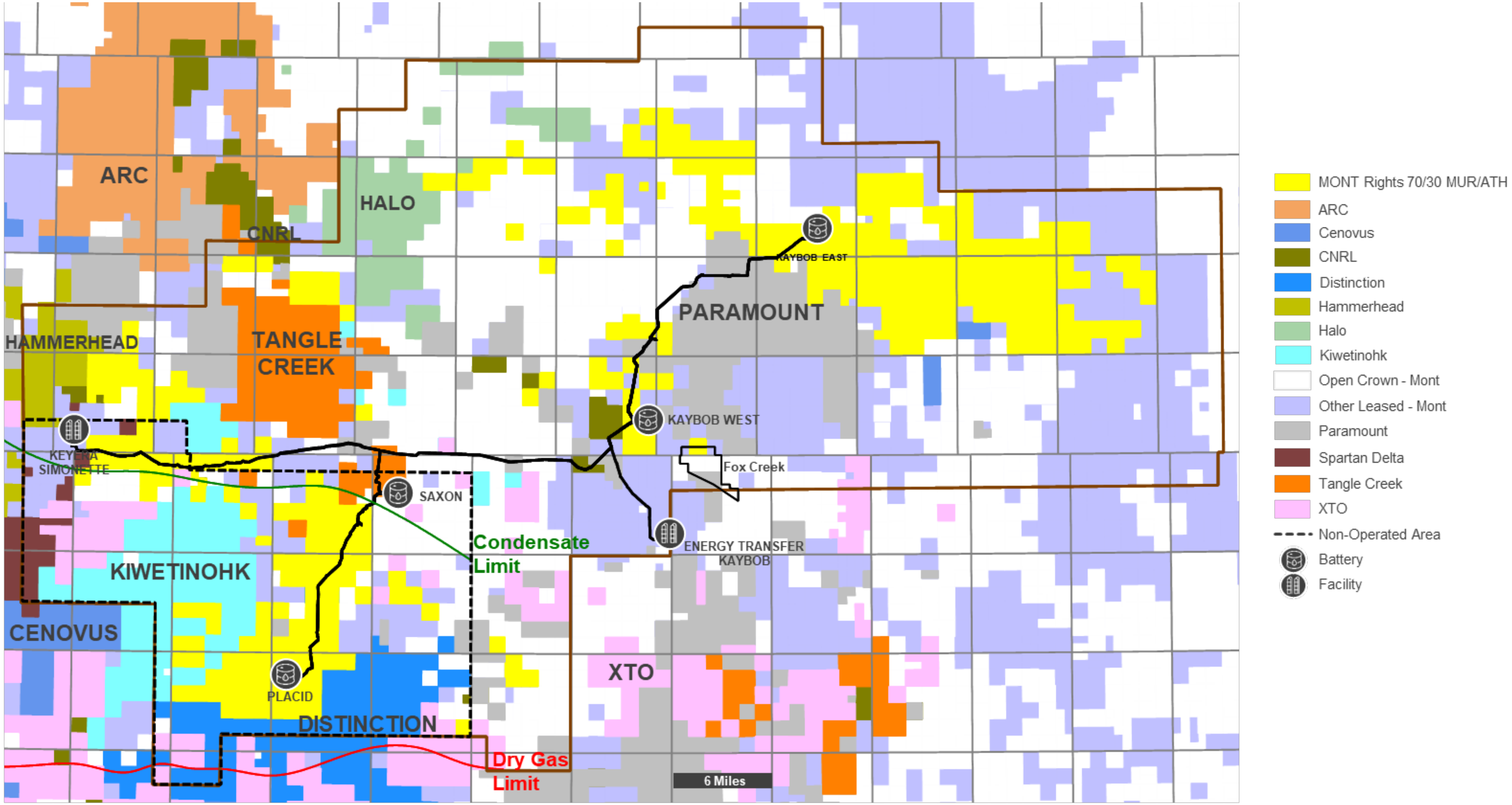
# Tupper Montney

## Peer Acreage



# Placid Montney

## Peer Acreage



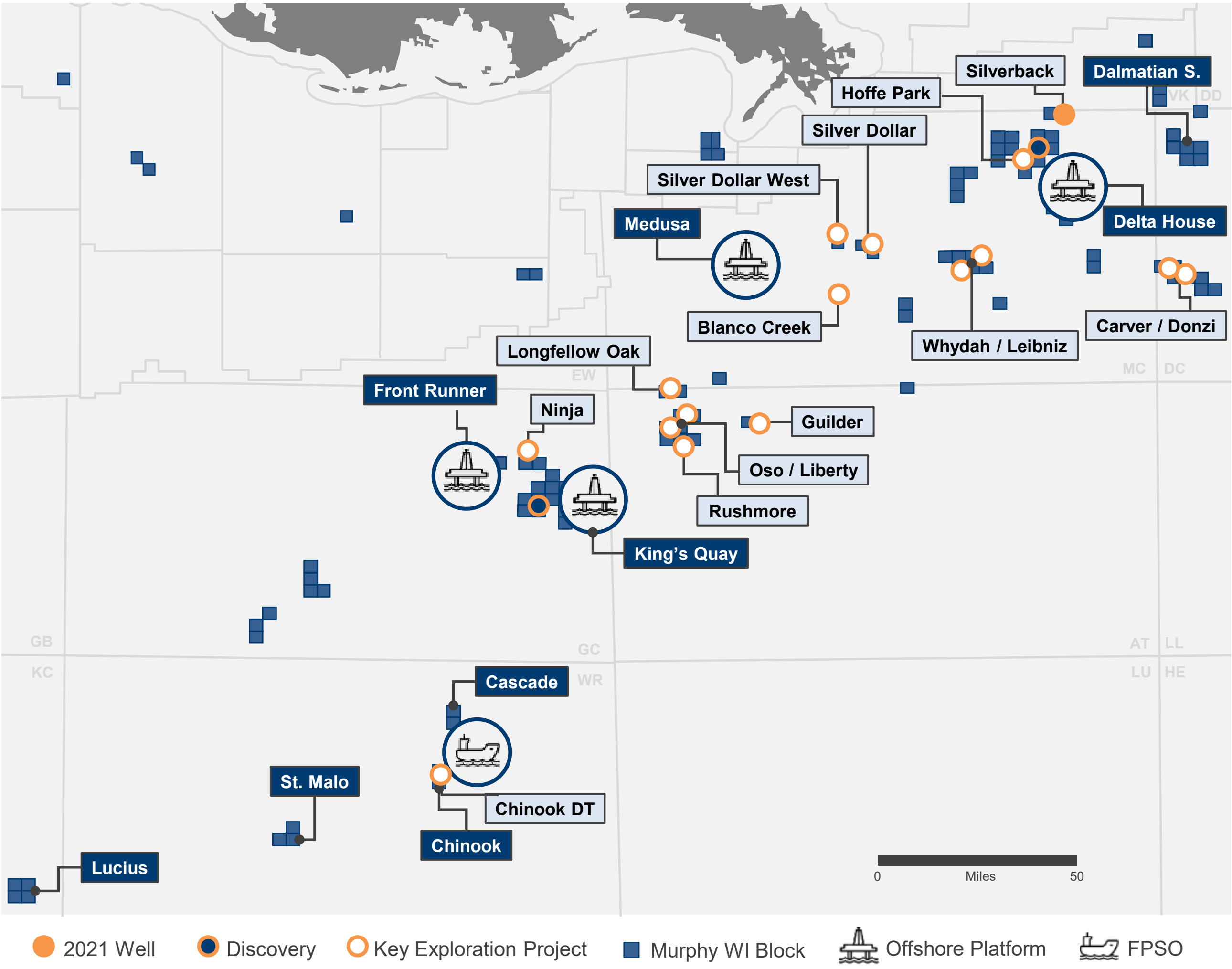
# Gulf of Mexico

## Murphy Blocks

| PRODUCING ASSETS | | |
|---|---|---|
| **Asset** | **Operator** | **Murphy WI[1]** |
| Cascade | Murphy | 80% |
| Chinook | Murphy | 80% |
| Clipper | Murphy | 80% |
| Cottonwood | Murphy | 80% |
| Dalmatian | Murphy | 56% |
| Front Runner | Murphy | 50% |
| Habanero | Shell | 27% |
| Kodiak | Kosmos | 48% |
| Lucius | Anadarko | 13% |
| Marmalard | Murphy | 27% |
| Marmalard East | Murphy | 68% |
| Medusa | Murphy | 48% |
| Neidermeyer | Murphy | 53% |
| Powerball | Murphy | 75% |
| Son of Bluto II | Murphy | 27% |
| St. Malo | Chevron | 20% |
| Tahoe | W&T | 24% |
| Thunder Hawk | Murphy | 50% |

*Note: Anadarko is a wholly-owned subsidiary of Occidental Petroleum*
*1 Excluding noncontrolling interest*

### Gulf of Mexico Exploration Area

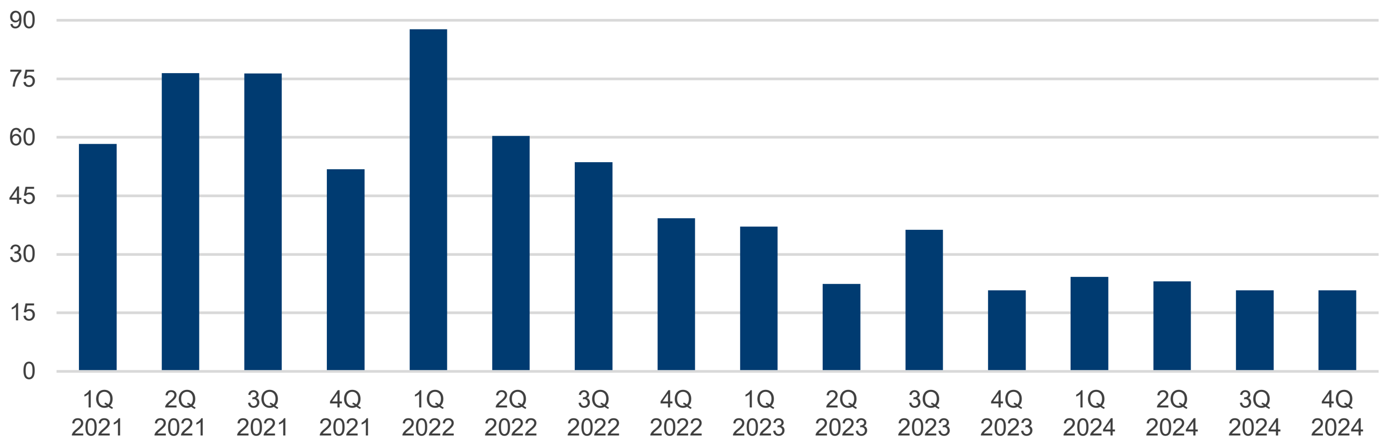


# Gulf of Mexico

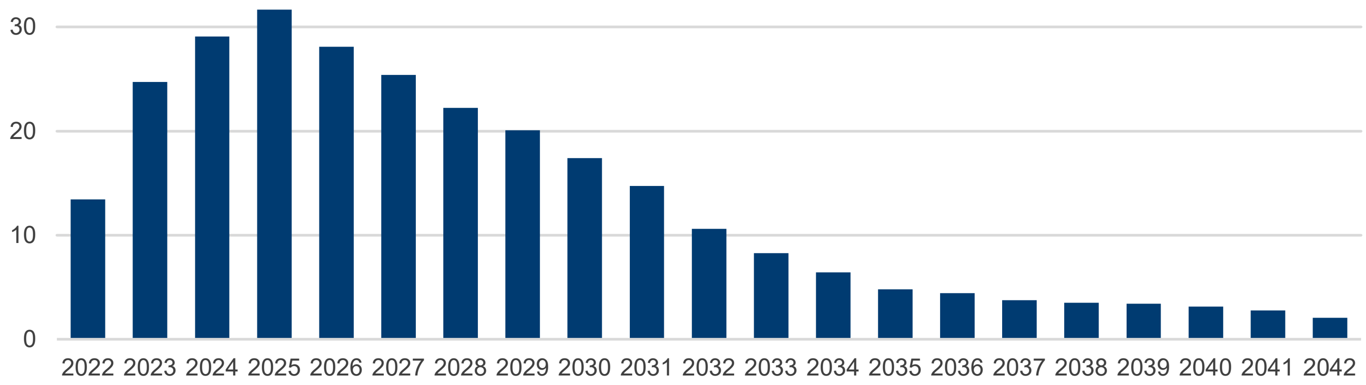
## Major Projects CAPEX and Production Cadence

*Major projects include Khaleesi, Mormont, Samurai and St. Malo waterflood*

### Major Projects Net CAPEX *$MM*




### Major Projects Net Production *MBOEPD*



# 2021 Exploration Plan
## Potiguar Basin, Brazil

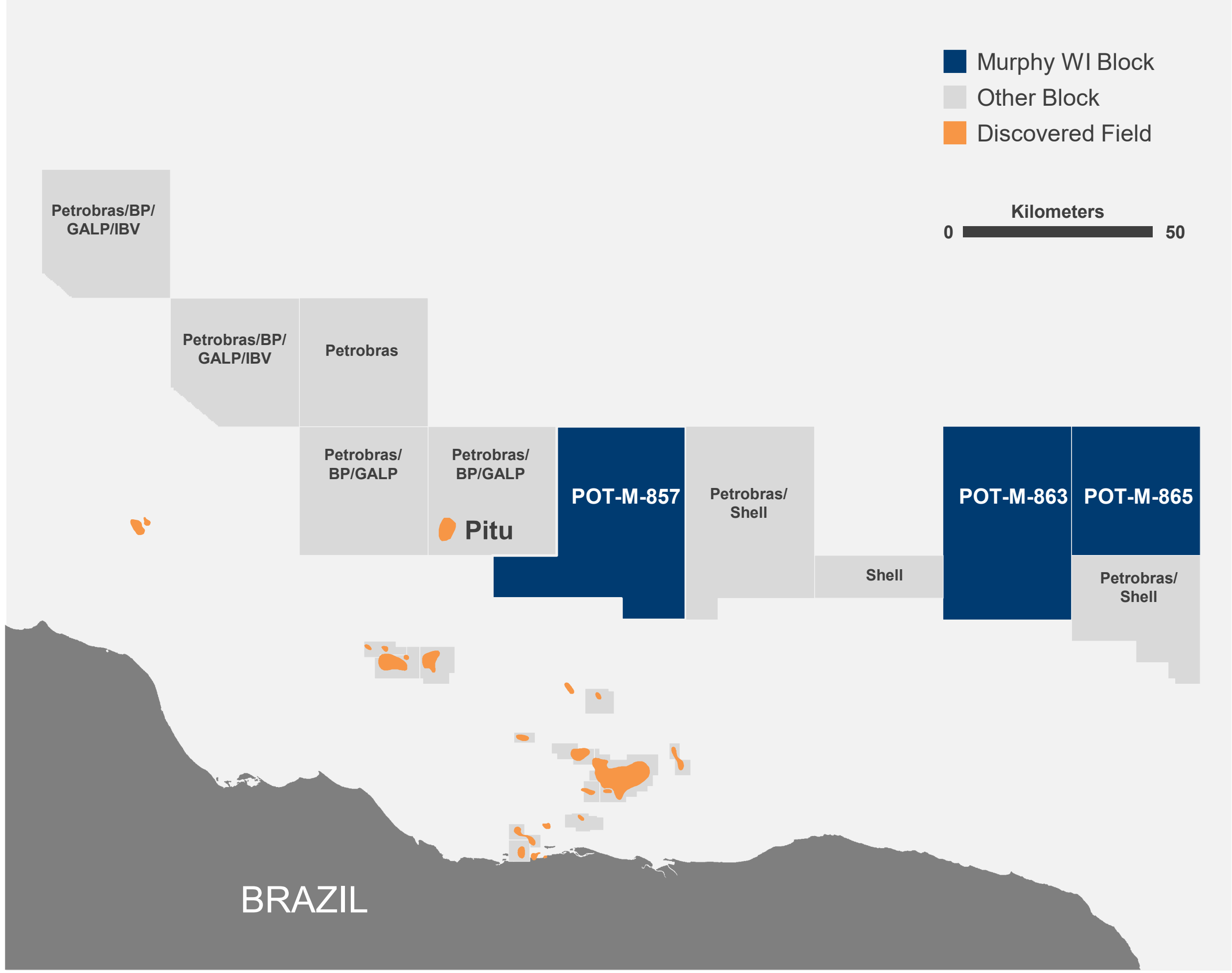
### Asset Overview

- Wintershall Dea 70% (Op), Murphy 30%
- 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 exploration
  - Pitu step-out into deepwater
- Interpreting final seismic data
- Targeting late 2022 to early 2023 spud

Potiguar Basin



# 2021 Exploration Plan
Salina Basin, Mexico

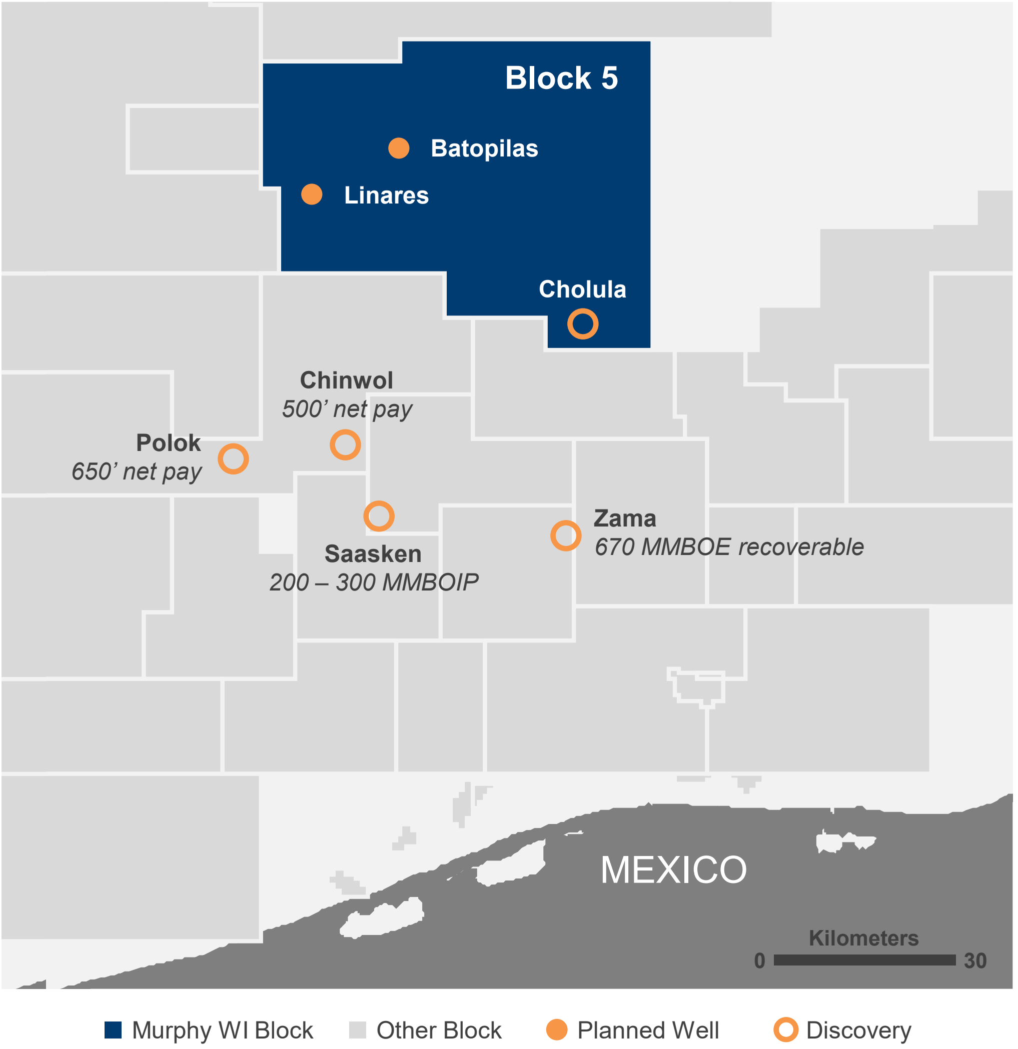
## Block 5 Overview

- Murphy 40% (Op), Petronas 30%, Wintershall Dea 30%
- 34 leads / prospects
- Mean to upward gross resource potential
  - 800 MMBO – 2,000 MMBO
- Proven oil basin in proximity to multiple oil discoveries in Miocene section
- Targeting exploration drilling campaign in 2022
  - Initial prospects identified – Batopilas and Linares
  - Progressing permitting and regulatory approvals

## Cholula Appraisal Program

- Discretionary 3-year program approved by CNH
- Up to 3 appraisal wells + geologic/engineering studies

Salina Basin



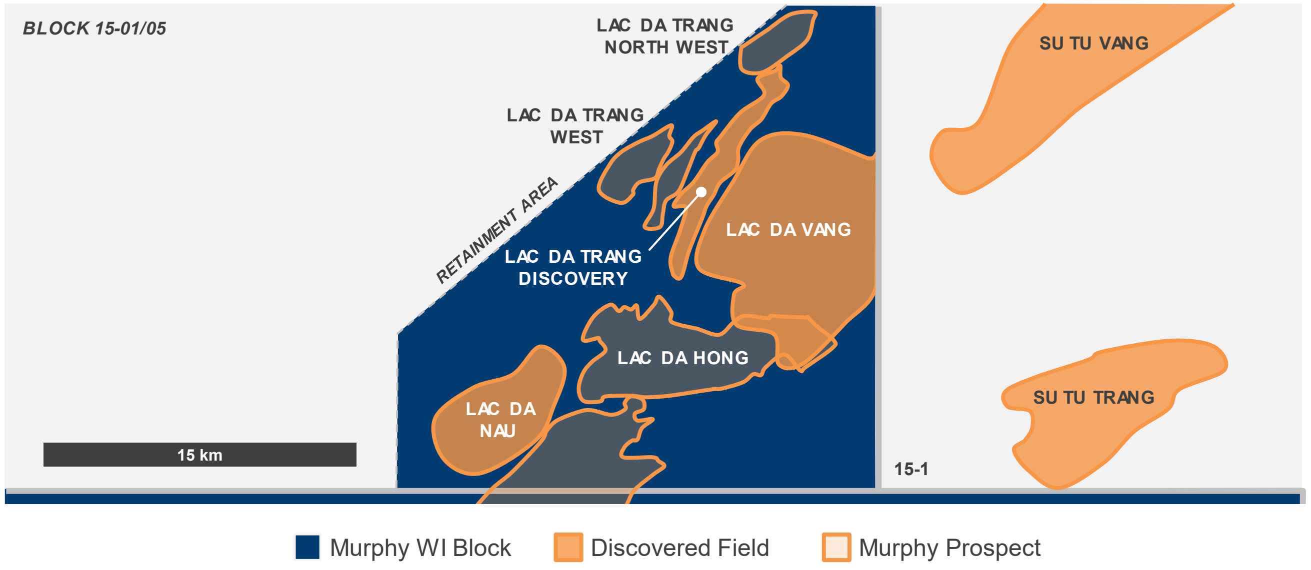
## Asset Overview

- Murphy 40% (Op), PVEP 35%, SKI 25%

## Block 15-1/05

- Received approval of the Lac Da Vang (LDV) retainment / development area
- LDV field development plan submitted to government
- LDT-1X discovery in 2019
- Maturing remaining block prospectivity
- LDT-1X discovery and other exploration upside has potential to add bolt-on resources to LDV

Cuu Long Basin



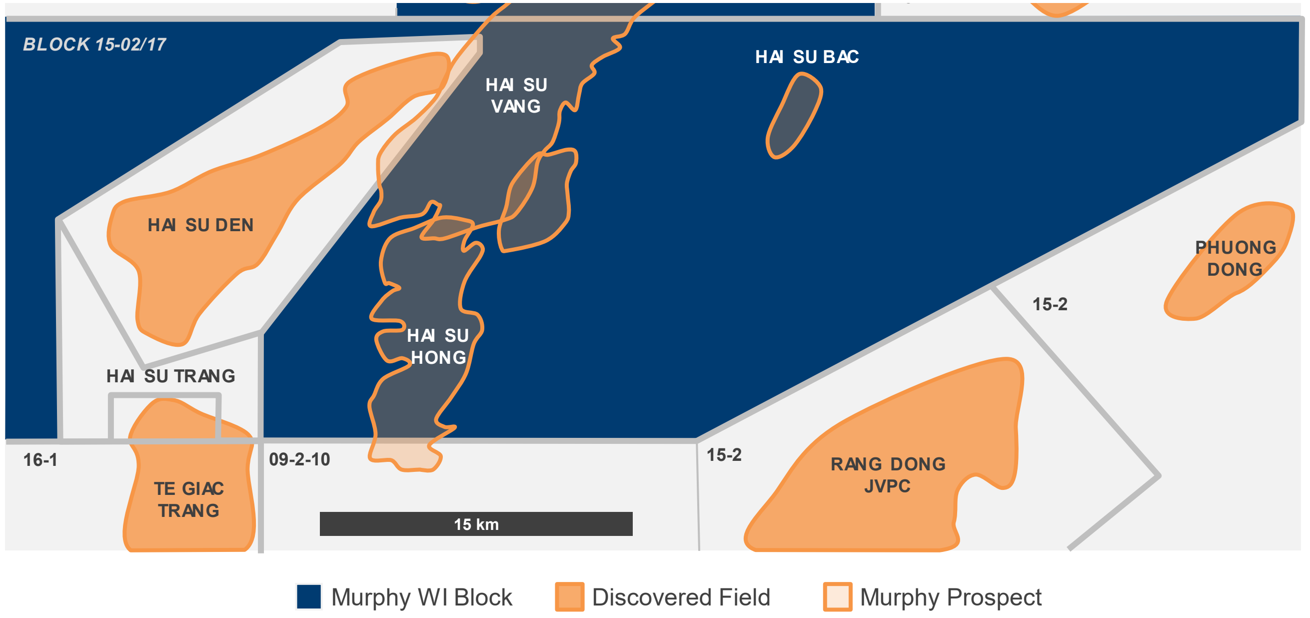
## Asset Overview

- Murphy 40% (Op), PVEP 35%, SKI 25%

## Block 15-2/17

- Signed joint operating agreement with partners in 4Q 2020
  - 3-year primary exploration period
  - 1 well commitment in 2022
- Seismic reprocessing, geological / geophysical studies ongoing

Cuu Long Basin



MURPHY
OIL CORPORATION

# 2021
# FIRST QUARTER EARNINGS

## CONFERENCE CALL & WEBCAST

MAY 6, 2021

ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER