Cautionary Statement & Investor Relations Contacts

Cautionary Note to U.S. 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: 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; natural hazards impacting our operations; 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; and adverse developments in the U.S. 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 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. 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 such as future “Free Cash Flow” and future “EBITDA”. Definitions of these measures are included in the appendix.

Cautionary Statement & Investor Relations Contacts

Kelly Whitley
VP, Investor Relations & Communications
281-675-9107
kelly_whitley@murphyoilcorp.com

Bryan Arciero
Sr. Investor Relations Advisor
281-675-9339
bryan_arciero@murphyoilcorp.com

Megan Larson
Sr. Investor Relations Analyst
281-675-9470
megan_larson@murphyoilcorp.com
Executing Our 2019 Plan

**PRODUCING**
Oil-Weighted Assets
- 159 MBOEPD, >60% Oil
- >23% increase in Eagle Ford Shale from 1Q
- Lowered LOE/BOE to <$9 in 2Q 2019

**GENERATING**
High Margin Realizations
- 94% oil volumes sold at premium to WTI
- >$26 EBITDA/BOE
- >$38 EBITDA/BOE
- US & Canada offshore
- Additional oil hedges average >$60 WTI

**INCREASING**
Financial Strength
- Returned >$340 MM to shareholders
- Delivered 4.4% dividend yield
- Repaid revolver to zero balance

**TRANSFORMING**
with Accretive Acquisitions
- Closed Gulf of Mexico & Malaysia transactions
- Increased reserves liquids-weighting by 5%
- Top 5 operator in Gulf of Mexico

**BUILDING**
Profitable Production
- Sanctioned 3 Gulf of Mexico projects set to deliver sustainable FCF
- Drilled successful well at Dalmatian DC4 #2
2Q 2019 Financial Results

2Q 2019 Results from Continuing Operations
• Net income $92 MM
• Adjusted net income $36 MM

2Q 2019 Accounting Adjustments
• Malaysia reported as discontinued operations
• One-off items, pre-tax
  • $15 MM non-cash mark-to-market charge on contingent consideration
  • $8 MM charge for transaction costs
  • $51 MM non-cash mark-to-market gain on crude oil derivative contracts
  • $13 MM credit for Canadian tax reform

2Q 2019 ($MM Except Per Share)

<table>
<thead>
<tr>
<th>Net Income Attributable to Murphy</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Income (loss)</td>
<td>$92.3</td>
</tr>
<tr>
<td>$/Diluted share</td>
<td>$0.54</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Adjusted Earnings</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted income (loss)</td>
<td>$35.7</td>
</tr>
<tr>
<td>$/Diluted share</td>
<td>$0.21</td>
</tr>
</tbody>
</table>

NOTE: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated.
Maintaining Financial Discipline

Cash Flow from Continuing Operations

• Cash flow exceeded property additions and dry hole costs by $60 MM
• $93 MM in-flow from working capital related to MP GOM transition
• $22 MM non-cash long-term compensation

Additional Cash Flow

• Received approximately $20 MM cash proceeds from non-core asset sale

Subsequent to Quarter End

• Credit facility and term loan borrowings fully repaid
• Increased WTI hedges
  • 3,000 BOPD for remaining 2019
  • 4,000 BOPD for 2020

### 2Q 2019 Cash Flow Attributable to Murphy ($MM)

<table>
<thead>
<tr>
<th></th>
<th>2Q</th>
<th>YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net cash provided by continuing operations</td>
<td>$438.2</td>
<td>$655.4</td>
</tr>
<tr>
<td>Property additions and dry hole costs</td>
<td>($374.8)</td>
<td>($645.1)</td>
</tr>
<tr>
<td>Free Cash Flow</td>
<td>$63.4</td>
<td>$10.3</td>
</tr>
</tbody>
</table>

### US WTI Hedges

- July 1, 2019 – July 31, 2019: 20,000 BOPD @ $63.64/BBL
- Aug 1, 2019 – Dec 31, 2019: 23,000 BOPD @ $63.17/BBL
- Jan 1, 2020 – Dec 31, 2020: 24,000 BOPD @ $59.67/BBL

### AECO Hedges

- July 1, 2019 – Dec 31, 2020: 59 MMCFD @ C$2.81/MCF

NOTE: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated.
## Achieving Premium Oil-Weighted Realizations

**>94,000 BBLs/Day Sold**

<table>
<thead>
<tr>
<th>Field-Level EBITDA/BOE</th>
<th>Eagle Ford Shale</th>
<th>North America Offshore</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2Q 2019</strong></td>
<td><strong>$64/BBL</strong></td>
<td><strong>$63/BBL</strong></td>
</tr>
<tr>
<td><strong>$35/BOE</strong></td>
<td></td>
<td><strong>$38/BOE</strong></td>
</tr>
</tbody>
</table>

**Oil-Weighted Realizations**

**2Q 2019**

**NOTE:** Realizations include transportation costs

### Sales Volumes & Differentials

**2Q 2019 Total Company**

- **Differentials vs $59.82 WTI**
  - **26%** Mars [+5.85/BBL]
  - **21%** Brent [+8.47/BBL]
  - **35%** MEH [+6.54/BBL]
  - **13%** LLS [+7.53/BBL]
  - **6%** Other

**94% Sold At Premium to $59.82 WTI**

**94,000 BBLs/Day Sold**
Production Update
Outperforming in 2Q 2019

2Q 2019 Production 159 MBOEPD, 67% Liquids
• > 96,000 BBLs/day oil production
• Exceeded 2Q guidance by 5,500 BOEPD
• Gulf of Mexico 2,800 BOEPD
  • New assets exceeding expectations
  • Reduced downtime
• Canada Offshore (800) BOEPD
  • Extended downtime, non-operated
• Onshore Canada 3,500 BOEPD
  • Increased drilling efficiencies and outperformance

NOTE: NA Offshore includes Gulf of Mexico & Offshore Canada.
Long History of Benefitting Shareholders

> $6.3 Billion
Returned to Shareholders
Since 1961

> $4.4 Billion
Returned to Shareholders
In last 10 years

> $1.6 Billion
in Share Repurchases
2012 – 1H 2019

Free Cash Flow Yield 2016 - 2019E

Dividend + Buyback – Issuance Yield Annualized 2016 - 2019E

Cash Paid to Shareholders $MM 1997 - 2019E

Note: FCF Yield = CFO Less Property Additions & Dry Hole Costs Divided by Market Cap (Avg. from 12/31/16 to 7/19/19)
Source: Bloomberg
Peer Group: DVN, COG, WLL, APA, MRO, APC, XEC, ECA, RRC, CNX, NBL, SWN, HES, SM, MTDR, CHK

Note: 2019 YTD Buybacks includes MUR Buybacks in 2Q 2019 and Peer Buybacks in 1Q 2019
Source: Bloomberg, Avg. Market Cap from 12/31/16 to 7/19/19
Peer Group: DVN, CNX, APA, HES, APC, NBL, COG, XEC, MRO, RRC, CHK, WLL, ECA, SWN, SM
Onshore Portfolio Update
2019 Well Delivery Plan

- 91 wells online

2Q 2019 44 MBOEPD, 74% Oil, 88% Liquids

- > 23% increase in volumes from 1Q 2019
- 35 wells online, 91% liquids
  - 23 Karnes – 14 Lower EFS, 3 Upper EFS, 6 Austin Chalk
  - 12 Tilden – Lower EFS

3Q 2019

- 25 wells online
  - 10 Tilden – Lower EFS
  - 15 Catarina – 11 Lower EFS, 6 Upper EFS

4Q 2019

- 18 wells online
  - 8 Tilden – Lower EFS
  - 10 Catarina – Lower EFS

NOTE: EFS = Eagle Ford Shale
23 Karnes Wells Online

- Exceeded average type curve in Lower and Upper EFS
  - Avg IP30 925 BOEPD Austin Chalk, 89% liquids
  - Avg IP30 1,200 BOEPD Upper EFS, 92% liquids
  - Avg IP30 1,300 BOEPD Lower EFS, 91% liquids
- Continued execution of Austin Chalk delineation

12 Tilden Wells Online

- Advanced wells into 2Q from 3Q
- Achieved record IP30s for Central Tilden
  - 8 Lower EFS wells Central Tilden
    - Average IP30 1,370 BOEPD, 92% liquids
  - 4 Lower EFS wells East Tilden
    - Average IP30 700 BOEPD, 94% liquids
2019 Well Delivery Plan Complete
- 10 wells online

2Q 2019 9,300 BOEPD, 61% liquids
- > 25% increase in volumes from 2Q 2018
- 6 wells online
- Closed Kaybob East cashless acreage swap
  - Acquired 20,000 gross acres in exchange for 5,800 gross acres
- 3 Simonette wells resumed production in 3Q 2019

2H 2019 Land Retention Plan
- Drill 13 wells
- Scheduled to come online in 2020

2019 Online Wells

<table>
<thead>
<tr>
<th>Area</th>
<th>Pad</th>
<th>Wells Online</th>
<th>IP30 (BOEPD)</th>
<th>Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>08-03</td>
<td>3</td>
<td>1,400*</td>
<td>86%</td>
</tr>
<tr>
<td>B</td>
<td>05-23</td>
<td>2</td>
<td>1,054</td>
<td>86%</td>
</tr>
<tr>
<td>C</td>
<td>05-19</td>
<td>2</td>
<td>651*</td>
<td>91%</td>
</tr>
<tr>
<td>D</td>
<td>16-29</td>
<td>2</td>
<td>858*</td>
<td>91%</td>
</tr>
</tbody>
</table>

* Well volumes constrained due to current facility limitations.
**2019 Well Delivery Plan Complete**
- 8 wells online

**2Q 2019 37 MBOEPD, 100% Natural Gas**
- 5 wells online
- New wells trending in line with 18 BCF type curve

**Successful AECO Price Mitigation**
- Realized 2Q 2019 C$1.82/MCF* vs AECO realized average of C$1.03/MCF
- Projected FY 2019 C$2.27/MCF* vs AECO realized average of C$1.69/MCF

* C$0.28 Transportation Cost to AECO Not Subtracted

---

### Tupper Montney Natural Gas Realizations 2Q 2019 $CAD/MCF

<table>
<thead>
<tr>
<th>Price Exposure</th>
<th>Realized Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>MUR AECO Realized**</td>
<td>$1.03</td>
</tr>
<tr>
<td>Hedge Uplift</td>
<td>$0.51</td>
</tr>
<tr>
<td>Diversification Uplift</td>
<td>$0.28</td>
</tr>
<tr>
<td>Realized Price</td>
<td>$1.82</td>
</tr>
</tbody>
</table>

* C$0.28 of Transportation Cost Not Subtracted

---

### Mitigating AECO Exposure

2Q 2019 Tupper Montney Natural Gas Sales

- **Dawn Price Exposure**: 5%
- **Malin Price Exposure**: 9%
- **Chicago Price Exposure**: 18%
- **Hedged**: 26%
- **AECO Price Exposure**: 42%

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### Price Exposure

- **Chicago Price Exposure**: 42%
- **Malin Price Exposure**: 26%
- **Chicago Price Exposure**: 18%
- **Hedged**: 9%

---

### Canada Onshore

**Tupper Montney Update**

- **2019 Well Delivery Plan Complete**

**2Q 2019 37 MBOEPD, 100% Natural Gas**

**Successful AECO Price Mitigation**

- Realized 2Q 2019 C$1.82/MCF* vs AECO realized average of C$1.03/MCF
- Projected FY 2019 C$2.27/MCF* vs AECO realized average of C$1.69/MCF

* C$0.28 Transportation Cost to AECO Not Subtracted
Offshore Portfolio Update
2Q 2019 Production 58 MBOEPD, 90% Liquids

- Closed Gulf of Mexico acquisition
- Exceeded production guidance from new assets by 1,200 BOEPD and legacy assets by 1,600 BOEPD

Dalmatian DC4 #2 Well

- Well drilled and completed, online 4Q 2019
- Incremental oil rate ~6,000 BOEPD gross
- Payback period < 18 months
- IRR > 90%

Hoffe Park #2 Well

- Oil discovered in multiple zones
Gulf of Mexico
King’s Quay Delivers Low-Risk Cash Flows

King’s Quay Floating Production System (FPS)
- In service 1H 2022
- 50% working interest
  - Optionality to sell down
- Available capacity for third-party production handling agreement fees generating incremental cash flow

Net Project CAPEX $MM

Net Operating Cash Flow $MM

Cash Flow Generated through 2042
Khaleesi/Mormont > 30% IRR
- Gross resource ~165 MMBOE, 90% Liquids
- 7 development wells planned – 4 previously drilled

Samurai > 35% IRR
- Gross resource ~60 MMBOE, 90% Liquids
  - Potential Upside ~15 MMBOE
- 4 development wells planned

WTI $55/BBL, 2019-2023

Production volumes may vary +/- 3% based on timing and performance
Production volumes, reserves and financial amounts exclude non-controlling interest
Gulf of Mexico
Short Cycle Capital Projects Deliver Accelerated Returns

<table>
<thead>
<tr>
<th>New Wells</th>
<th>Completions &amp; Tie-Backs</th>
<th>Workovers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dalmatian DC4 #2</td>
<td>Nearly Headless Nick</td>
<td>Cottonwood</td>
</tr>
<tr>
<td>Son of Bluto II</td>
<td>Ourse</td>
<td>Calliope</td>
</tr>
</tbody>
</table>

**21 MMBOE Total Net Resources**

**$7.50/BBL CAPEX**

**>80% IRR Average Project**

WTI $55/BBL, 2019-2023

**Net CAPEX $MM**

**Net Production MBOEPD**

Production volumes may vary +/- 3% based on timing and performance.

Production volumes, reserves and financial amounts exclude non-controlling interest.
Production & CAPEX Guidance

**Production**
- **3Q 2019**: 192 - 196 MBOEPD
- **FY 2019**: 174 - 178 MBOEPD

**CAPEX**
- **FY 2019**: $1.35 - $1.45 Billion

**2019 CAPEX by Asset**
- New Gulf of Mexico Assets: 45%
- Onshore Canada: 19%
- Exploration: 17%
- Eagle Ford Shale: 9%
- NA Offshore: 10%

**2019 CAPEX by Future Production Year**
- 2019 Production: 67%
- 2020 Production: 6%
- 2021+ Production: 26%

**2019 CAPEX Allocated to New Gulf of Mexico Assets**
- Short-Term Tie-Back Projects: 20%
- Long-Term Tie-Back Projects: 60%
- King’s Quay Facility: 20%

**NOTE:** FY CAPEX excludes $20 MM allocated to assets held for sale.
Positioning Company for Long-Term Value Creation

- **TRANSFORMING**
  - Portfolio by adding oil-weighted, high-margin assets

- **PRODUCING**
  - Oil-weighted assets that realize premium pricing

- **RAMPING**
  - Eagle Ford Shale production

- **EXECUTING**
  - Short cycle Gulf of Mexico field development projects

- **OFFERING**
  - Investors exploration upside

- **FOCUSING**
  - On shareholder priorities
Appendix
Appendix

Non-GAAP Reconciliation
Abbreviations
Guidance
Hedging Positions
Current Financial Position
Environmental, Social and Governance
Non-GAAP Financial Measure Definitions & 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.

<table>
<thead>
<tr>
<th>$ Millions, except per share amounts</th>
<th>Three Months Ended – June 30, 2019</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Net income attributable to Murphy (GAAP)</td>
<td>92.3</td>
<td>45.5</td>
</tr>
<tr>
<td>Discontinued operations loss (income)</td>
<td>(24.4)</td>
<td>(70.7)</td>
</tr>
<tr>
<td>Income from continuing operations</td>
<td>67.9</td>
<td>(25.2)</td>
</tr>
<tr>
<td>Mark-to-market (gain) los on crude oil derivative contracts</td>
<td>(40.2)</td>
<td>10.1</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on contingent consideration</td>
<td>12.1</td>
<td>–</td>
</tr>
<tr>
<td>Business development transaction costs</td>
<td>6.2</td>
<td>–</td>
</tr>
<tr>
<td>Impact of tax reform</td>
<td>(13.0)</td>
<td>–</td>
</tr>
<tr>
<td>Foreign exchange losses (gains)</td>
<td>2.7</td>
<td>7.1</td>
</tr>
<tr>
<td><strong>Adjusted Income (loss) attributable to Murphy (Non-GAAP)</strong></td>
<td><strong>35.7</strong></td>
<td><strong>(8.0)</strong></td>
</tr>
<tr>
<td><strong>Adjusted income (loss) from continuing operations per diluted share</strong></td>
<td><strong>0.21</strong></td>
<td><strong>(0.05)</strong></td>
</tr>
</tbody>
</table>

\(^1\) ‘Attributable to Murphy’ represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
EBITDA and EBITDAX

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

Management believes that EBITDA and EBITDAX provides useful information for assessing Murphy's financial condition and results of operations and it is a widely accepted financial indicator of the ability of a company to incur and service debt, fund capital expenditure programs, and 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 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). EBITDA and EBITDAX have certain limitations regarding financial assessments because they excludes 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.

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<td>(70.7)</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>9.1</td>
<td>2.6</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>54.1</td>
<td>44.3</td>
</tr>
<tr>
<td>DD&amp;A expense</td>
<td>246.0</td>
<td>190.8</td>
</tr>
<tr>
<td><strong>EBITDA attributable to Murphy (Non-GAAP)</strong></td>
<td><strong>377.1</strong></td>
<td><strong>212.5</strong></td>
</tr>
<tr>
<td>Exploration expense</td>
<td>30.7</td>
<td>18.9</td>
</tr>
<tr>
<td><strong>EBITDAX attributable to Murphy (Non-GAAP)</strong></td>
<td><strong>407.8</strong></td>
<td><strong>231.4</strong></td>
</tr>
</tbody>
</table>

1 ‘Attributable to Murphy’ represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
ADJUSTED EBITDA

Murphy defines Adjusted EBITDA as income from continuing operations attributable to Murphy1 before interest, taxes, depreciation and amortization (DD&A), impairment expense, foreign exchange gains and losses, mark-to-market loss 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.

<table>
<thead>
<tr>
<th>$ Millions, except per BOE amounts</th>
<th>Three Months Ended – June 30, 2019</th>
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<tr>
<td>EBITDA attributable to Murphy (Non-GAAP)</td>
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<td>Business development transaction costs</td>
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</tr>
<tr>
<td>Accretion of asset retirement obligations</td>
<td>9.9</td>
<td>6.4</td>
</tr>
<tr>
<td>Foreign exchange losses (gains)</td>
<td>3.0</td>
<td>(12.2)</td>
</tr>
<tr>
<td>Adjusted EBITDA attributable to Murphy (Non-GAAP)</td>
<td>362.4</td>
<td>194.0</td>
</tr>
<tr>
<td>Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)</td>
<td>14,268</td>
<td>11,019</td>
</tr>
<tr>
<td>Adjusted EBITDA per BOE (Non-GAAP)</td>
<td>26.43</td>
<td>17.61</td>
</tr>
</tbody>
</table>

1 ‘Attributable to Murphy’ represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
ADJUSTED EBITDAX

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

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Non-GAAP Reconciliation

<table>
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<tr>
<th>$ Millions, except per BOE amounts</th>
<th>Three Months Ended – June 30, 2019</th>
<th>Three Months Ended – June 30, 2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>EBITDAX attributable to Murphy (Non-GAAP)</td>
<td>407.8</td>
<td>231.4</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on crude oil derivative contracts</td>
<td>(50.8)</td>
<td>(12.7)</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on contingent consideration</td>
<td>15.4</td>
<td>-</td>
</tr>
<tr>
<td>Business development transaction costs</td>
<td>7.8</td>
<td>-</td>
</tr>
<tr>
<td>Accretion of asset retirement obligations</td>
<td>9.9</td>
<td>6.4</td>
</tr>
<tr>
<td>Foreign exchange losses (gains)</td>
<td>3.0</td>
<td>(12.2)</td>
</tr>
<tr>
<td>Adjusted EBITDAX attributable to Murphy (Non-GAAP)</td>
<td>393.1</td>
<td>212.9</td>
</tr>
<tr>
<td>Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)</td>
<td>14,268</td>
<td>11,019</td>
</tr>
<tr>
<td>Adjusted EBITDAX per boe (Non-GAAP)</td>
<td>27.55</td>
<td>19.32</td>
</tr>
</tbody>
</table>

\(^1\) ‘Attributable to Murphy’ represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
FREE CASH FLOW

Murphy defines Free Cash Flow as net cash provided from continuing operations activities (as stated in the Consolidated Statements of Cash Flows) reduced by capital expenditures and investments.

Free Cash Flow is used by management to evaluate the company’s ability to internally fund acquisitions, exploration and development and evaluate trends between periods and relative to its industry competitors.

Free Cash Flow, 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). Free Cash Flow should not be considered in isolation or as a substitute for an analysis of Murphy’s GAAP results as reported.

<table>
<thead>
<tr>
<th>$ Millions</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019E1</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net cash provided from continuing operations activities (GAAP)</td>
<td>601</td>
<td>1,128</td>
<td>1,219</td>
<td>1,524</td>
<td>4,472</td>
</tr>
<tr>
<td>Property additions and dry hole costs</td>
<td>(927)</td>
<td>(1,010)</td>
<td>(1,103)</td>
<td>(1,336)</td>
<td>(4,375)</td>
</tr>
<tr>
<td>Free cash flow (Non-GAAP)</td>
<td>(326)</td>
<td>118</td>
<td>117</td>
<td>188</td>
<td>97</td>
</tr>
<tr>
<td>Market Cap on December 31</td>
<td>5,361</td>
<td>5,358</td>
<td>4,048</td>
<td>3,745</td>
<td>18,512</td>
</tr>
<tr>
<td>Free cash flow yield</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.5%</td>
</tr>
</tbody>
</table>

1 2019 estimate data obtained from Bloomberg estimates on July 17, 2019
DIVIDEND + BUYBACK – ISSUANCE YIELD ANNUALIZED

Murphy defines Dividend + Buyback issuance yield annualized as the sum of ‘Cash dividends paid’ (as stated in the Consolidated Statements of Cash Flows) plus cash paid for ‘Repurchase of common stock’ (as stated in the Consolidated Statements of Cash Flows) divided by the sum of market capitalization for the period being evaluated.

Dividend + Buyback – Issuance yield, 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). This metric should not be considered in isolation or as a substitute for an analysis of Murphy's GAAP results as reported.

Dividend + Buyback issuance yield annualized is used by management to evaluate the company’s return to shareholders.

<table>
<thead>
<tr>
<th>$ Millions</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019E</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash dividends paid (GAAP)</td>
<td>206.6</td>
<td>172.6</td>
<td>173.0</td>
<td>165.3</td>
<td>718</td>
</tr>
<tr>
<td>Purchase of treasury stock (GAAP)</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>300.0</td>
<td>300</td>
</tr>
<tr>
<td><strong>Total Paid to Shareholders</strong></td>
<td><strong>206.6</strong></td>
<td><strong>172.6</strong></td>
<td><strong>173.0</strong></td>
<td><strong>465.3</strong></td>
<td><strong>1,018</strong></td>
</tr>
<tr>
<td>Market Cap on December 31</td>
<td>5,361</td>
<td>5,358</td>
<td>4,048</td>
<td>3,7451</td>
<td>18,512</td>
</tr>
</tbody>
</table>

Dividend + Buyback – Issuance Yield Annualized 5.5%

1 MUR Market Cap July 17, 2019
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
E&P: Exploration & production
E&P: Estimated ultimate recovery
EUR: Finding & development
F&D: Finding & development
EUR: Floating liquefied natural gas
FLNG: General and administrative expenses
G&A: Gulf of Mexico
GOM: Hydrocarbon pore volume
HCPV: Joint venture
JV: Lease operating expense
LOE: Light Louisiana Sweet (a grade of crude oil, includes pricing for GOM and EFS)
LLS: Malaysia Crude Official Selling Price, differential to average monthly calendar price of Platts Dated Brent for delivery month
MCO: Millions of barrels of oil equivalent
MMBOE: Millions of cubic feet
MMCF: Millions of cubic feet per day
MMCFD: Million cubic feet equivalent per day
MMSTB: Million stock barrels
MCO: Natural gas liquid
NGL: Ratios of reserves to annual production
R/P: Ratio of reserves to annual production
TCF: Trillion cubic feet
TCPL: TransCanada Pipeline
TOC: Total organic content
TOC: West Texas Intermediate (a grade of crude oil)
WTI: Working interest
WI: Working interest
WTI: West Texas Intermediate (a grade of crude oil)
### 3Q 2019 Guidance

<table>
<thead>
<tr>
<th>Producing Asset</th>
<th>Liquids (BOPD)</th>
<th>Gas (MCFD)</th>
<th>Total (BOEPD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>US – Eagle Ford Shale</td>
<td>45,700</td>
<td>33,900</td>
<td>51,300</td>
</tr>
<tr>
<td>Gulf of Mexico excluding NCI¹</td>
<td>67,300</td>
<td>69,400</td>
<td>78,900</td>
</tr>
<tr>
<td>Gulf of Mexico including NCI</td>
<td>78,200</td>
<td>74,100</td>
<td>90,500</td>
</tr>
<tr>
<td>Canada – Tupper Montney</td>
<td>–</td>
<td>267,400</td>
<td>44,600</td>
</tr>
<tr>
<td>Kaybob Duvernay and Placid Montney</td>
<td>7,700</td>
<td>25,900</td>
<td>12,000</td>
</tr>
<tr>
<td>Offshore</td>
<td>6,800</td>
<td>–</td>
<td>6,800</td>
</tr>
<tr>
<td>Other</td>
<td>400</td>
<td>–</td>
<td>400</td>
</tr>
</tbody>
</table>

| | 3Q Production Volume (BOEPD) excluding NCI ² | 192,000 – 196,000 |
| | 3Q Production Volume (BOEPD) including NCI | 203,600 – 207,600 |
| | 3Q Exploration Expense ($MM) | $31 |
| | Full Year 2019 CAPEX ($BN) excluding NCI ³ | $1.35 – $1.45 |
| | Full Year 2019 Production (BOEPD) excluding NCI ⁴ | 174,000 – 178,000 |

---

1 Excludes Noncontrolling Interest of MP GOM of 10,900 BOPD Liquids & 4,700 MCFD Gas.
2 Excludes Noncontrolling Interest of MP GOM of 11,600 BOEPD.
3 Excludes Noncontrolling Interest of MP GOM of $48 MM and $20 MM for assets held for sale.
4 Excludes Noncontrolling Interest of MP GOM of 12,600 BOEPD.
## 2019 Hedging Positions

### United States

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (BBL/D)</th>
<th>Price (BBL)</th>
<th>Start Date</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI</td>
<td>Fixed Price Derivative Swap</td>
<td>20,000</td>
<td>$63.64</td>
<td>7/1/2019</td>
<td>7/31/2019</td>
</tr>
<tr>
<td>WTI</td>
<td>Fixed Price Derivative Swap</td>
<td>23,000</td>
<td>$63.17</td>
<td>8/1/2019</td>
<td>12/31/2019</td>
</tr>
<tr>
<td>WTI</td>
<td>Fixed Price Derivative Swap</td>
<td>24,000</td>
<td>$59.67</td>
<td>1/1/2020</td>
<td>12/31/2020</td>
</tr>
</tbody>
</table>

### Montney, Canada

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (MMCFD)</th>
<th>Price (BBL)</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>59</td>
<td>C$2.81</td>
<td>7/1/2019</td>
<td>12/31/2020</td>
</tr>
</tbody>
</table>
Current Financial Position
As of July 31, 2019

- $2.8 BN total debt, excluding capital leases
- Total liquidity $2.0 BN
- Approximately $450 MM of cash and cash equivalents
- Undrawn $1.6 BN unsecured senior credit facility
- 37% total debt to cap
- 33% net debt to cap

### Maturity Profile*

<table>
<thead>
<tr>
<th>Total Bonds Outstanding $BN</th>
<th>$2.8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weighted Avg Fixed Coupon</td>
<td>5.5%</td>
</tr>
<tr>
<td>Weighted Avg Years to Maturity</td>
<td>7.3</td>
</tr>
</tbody>
</table>

*As of July 31, 2019
Environmental, Social and Governance

GHG Emissions & Intensity

- 50% reduction in GHG emissions and intensity with 2018-2019 A&D activity
- Utilize natural gas to fuel frac pumps in Tupper Montney, leading to reduced GHG intensity
- Enhancing emissions forecasting in long-term plan

Average TRIR

- 0.32 Average TRIR over past 4 years

IOGP Recordable Spills

- 0 IOGP Recordable Spills YTD 2019

ISS Governance Score

- 75% ISS Governance Score vs peer average

ENVIRONMENTAL

SOCIAL RESPONSIBILITY

- El Dorado Promise – full college tuition support for El Dorado High School graduates in Arkansas
- United Way – partners for more than 50 years, over $13 million contributed
- Issued inaugural sustainability report April 2019

GOVERNANCE

- Received top rating for governance, or 75% higher than peer average
- In line with peers on environmental and social scores
- Board of Directors elected with average vote of approximately 99% over past 5 years

SAFETY

- Eagle Ford Shale well work five years lost time accident free
- Gulf of Mexico spill free since 2014
- Gulf of Mexico one year recordable free
- Vietnam seven years recordable free

~50% reduction in GHG emissions and intensity with 2018-2019 A&D activity