UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): September 5, 2018

MURPHY OIL CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	1-8590	71-0361522
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

300 Peach Street P.O. Box 7000, El Dorado, Arkansas	71730-7000
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code 870-862-6411

Not applicable
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter). Emerging growth company [ ]

**If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.
[ ]**

Item 7.01 Regulation FD Disclosure

As previously announced, Roger W. Jenkins, President and CEO of Murphy Oil Corporation, will present at the Barclays CEO Energy-Power Conference in New York on Thursday, September 6, 2018, at 9:05 a.m. Eastern Time (ET). Materials accompanying Mr. Jenkins' presentation are attached as Exhibit 99.1 hereto and will also be available on the Company's website at http://ir.murphyoilcorp.com.

Forward-Looking Statements: This report contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. Words such as "targets", "expectations", "plans", "forecasts", "projections" and other comparable terminology often identify forward-looking statements. 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 forecasted events not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a deterioration in the business or prospects of Murphy, adverse developments in Murphy business' markets, adverse developments in the U.S. or global capital markets, credit markets or economies in general. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, adverse foreign exchange movements, political and regulatory instability, and uncontrollable natural hazards. For further discussion of risk factors, see Murphy's most recent Annual Report on Form 10-K, on file with the U.S. Securities and Exchange Commission. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

The information in this Item 7.01, including Exhibit 99.1 attached hereto, is being furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that Section and shall not be incorporated by reference into any registration statement or other document pursuant to the Securities Act of 1933, as amended, or the Exchange Act, except as otherwise expressly stated in such filing.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

99.1 Presentation materials to be delivered at the Barclays CEO Energy-Power Conference on September 6, 2018.

Signature

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

MURPHY OIL CORPORATION

Date: September 5, 2018

By: /s/ Christopher D. Hulse

Christopher D. Hulse
Vice President and Controller

Exhibit Index

99.1	Presentation materials to be delivered at the Barclays CEO Energy-Power Conference on September 6, 2018.

BARCLAYS CEO
ENERGY-POWER CONFERENCE
SEPTEMBER 6, 2018
ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER
MURPHY
OIL CORPORATION

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 P_{MEAN} 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 as defined in 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 level of crude oil and natural gas prices, 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 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. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Investor Relations Contacts

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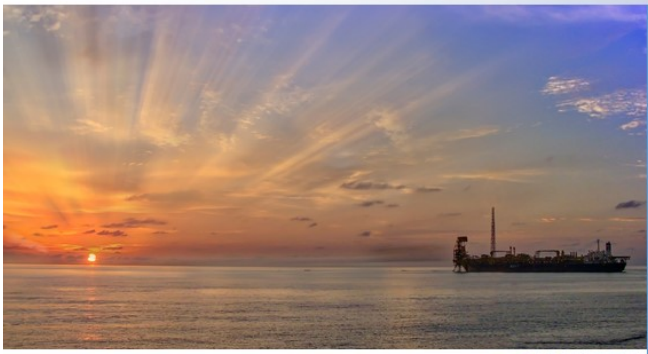
870-864-6324
Email: emily_mcelroy@murphyoilcorp.com

Agenda



01 COMPANY UPDATE

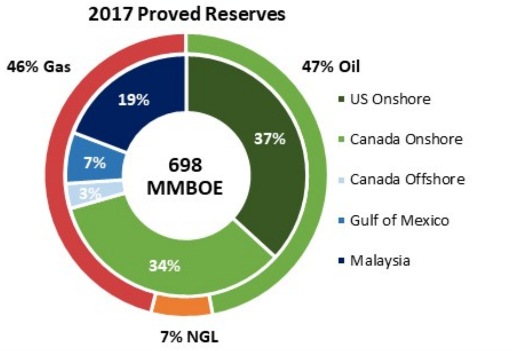
02 PORTFOLIO REVIEW

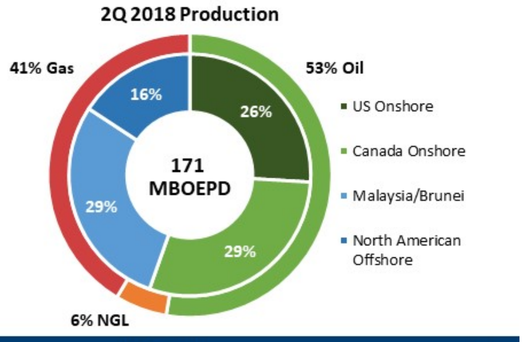
03 EXPLORATION REVIEW

04 TAKEAWAYS

Murphy At A Glance

- Long Corporate History, IPO 1956
- Global Offshore & North American Onshore Portfolio
- Diverse Portfolio Drives High Margins
- Exploration Renaissance with Recent Success
- Consistent Cash Flows from Long-Term Offshore Assets
- Growing Unconventional Assets in North American Onshore
- Low Leverage with Appropriate Liquidity & Strong Balance Sheet
- History of Shareholder-Focused Dividend Policy





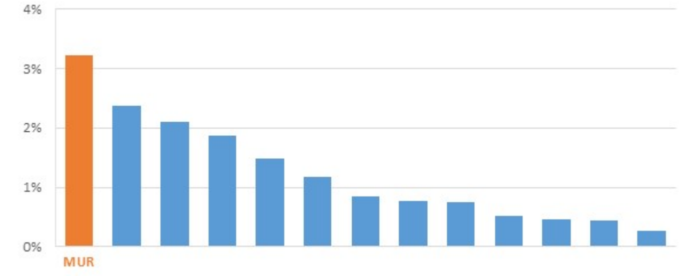
Enriching Shareholders with Long-Term Dividend Policy

- Returned $4.3 BN to Shareholders, Since 1961
- Returned > $2.5 BN to Shareholders in Last 10 Years
- Sustained High Dividend Yield Without Diluting Shareholders

Dividend + Buyback Payout % of Adj CFO*, 2015 – 2018E

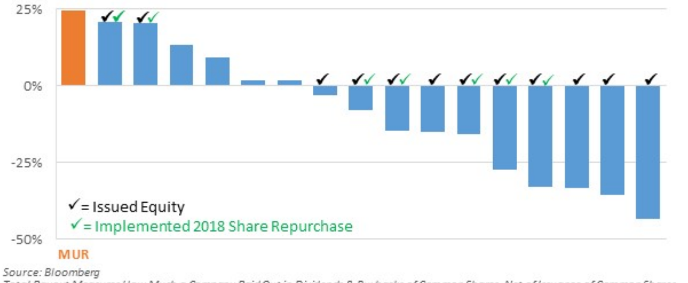
Source: Bloomberg
Note: Adjusted CFO = Cash Flow from Operations Before Changes in Non-Cash Working Capital
**2018 Buybacks Include 1H 2018 Reported, 2018E CF Based on Analyst Consensus CF per Share as of August 27, 2018*

Current Dividend Yield %



Source: Bloomberg, Close Price as of August 24, 2018
Peer Group: APA, APC, CHK, COG, DVN, ECA, EOG, HES, MRO, NBL, NFX, PXD, RRC, SWN, WLL, XEC

Dividend + Buyback – Equity Issuance Payout % of Adj CFO*, 2015 – 2018E



Source: Bloomberg
Total Payout Measures How Much a Company Paid Out in Dividends & Buybacks of Common Shares, Net of Issuance of Common Shares During the Period. Calculated as: Total Cash Common Dividends + Common Shares Buyback Amount – Issuance of Common Stocks

Updating Production & CAPEX Guidance

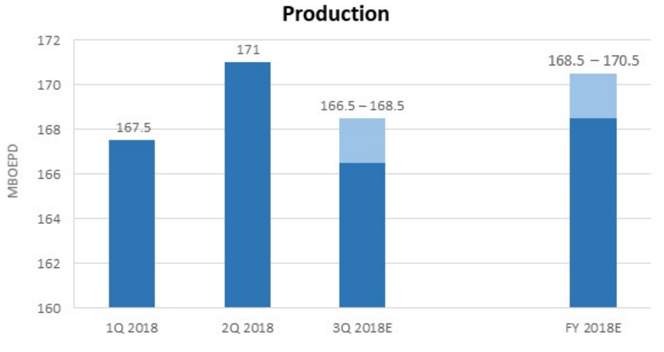
FY 18 Production Guidance 168.5 – 170.5 MBOEPD, 59% Liquids

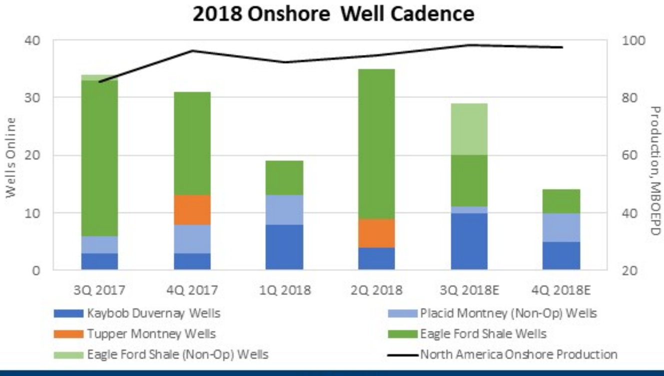
3Q 18 Guidance 166.5 – 168.5 MBOEPD, 59% Liquids

- Planned 3Q 18 Downtime, -7.4 MBOEPD
  - Annual Non-Operated Offshore Canada
  - Capital Project Execution in Malaysia
- Increased Onshore Production, +3.9 MBOEPD

2018 Annual CAPEX Spend $1.18 BN

- ~$730 MM Onshore
- ~$270 MM Offshore
- ~$140 MM Exploration





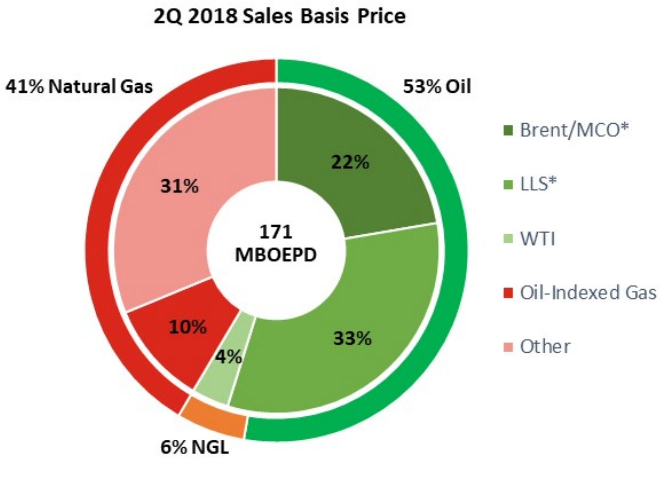
Delivering Our 2018 Plan

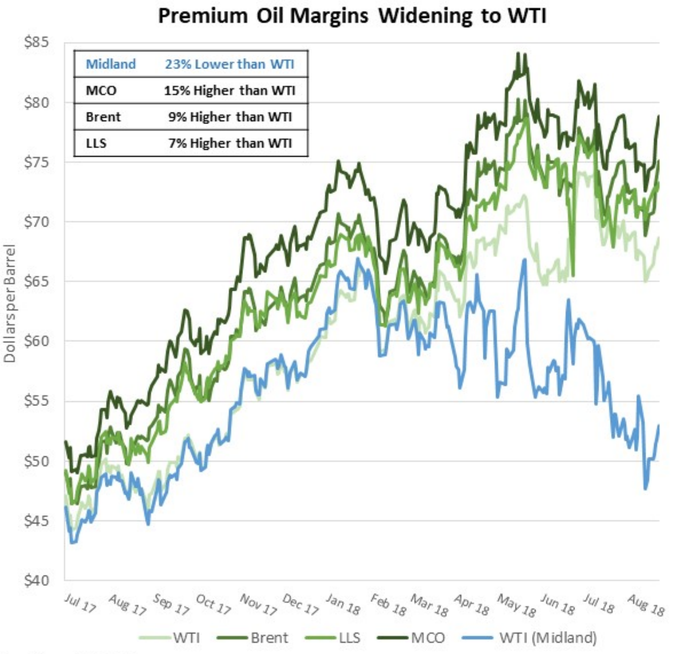
Driving Robust Production from Diversified Assets	Aligning Financial Priorities & Shareholder Value	Building a Strong Portfolio for the Future
• 2Q 18 Total Production 171 MBOEPD, 59% Liquids – Exceeding Guidance • 2Q 18 Offshore Production 76 MBOEPD, 72% Liquids • 2Q 18 Onshore Production 95 MBOEPD, 48% Liquids	• 2Q 18 Adjusted Income $63 MM • Annualized EBITDA/Avg Capital Employed 20% • Net Debt/Total Capital Employed 30% • Invested ~$300 MM 2Q 18 in CAPEX • Strong Liquidity Position of $2 BN with No Borrowing on Credit Facility • Returned 13% of Operating Cash Flow to Shareholders through Dividend	• Successful Delineation & Discovery Well at Samurai-2 (GC432) in Gulf of Mexico • Received Exploration Plan Approval for Mexico Block 5 • Achieved Kaybob Duvernay YE 19 D&C Cost Target in 2Q 18 • Record-Low Drilling & Completions Costs in Eagle Ford Shale & Kaybob Duvernay • Approved Long-Term Tupper Montney Expansion Project

Executing Our Strategy in 2Q 2018

Develop **DIFFERENTIATED PERSPECTIVES** In Underexplored Basins & Plays	✓ Returned to Offshore Exploration at Bottom of Cycle with Successful Delineation & Discovery at Samurai-2 in Gulf of Mexico ✓ Exploration Plan Approval for Mexico Deepwater Block 5
Continue to be a **PREFERRED PARTNER** to NOCs & Regional Independents	✓ Negotiated Operatorship & Increased Working Interest in Vietnam Block 15-1/05, with Partner PetroVietnam
BALANCE our Offshore Business by Acquiring & Developing Advantaged Unconventional NA Onshore Plays	✓ Beat 2Q Gulf of Mexico Production Guidance by ~1,700 BOEPD ✓ Increased Kaybob Duvernay Production 108% Y-O-Y ✓ Brought 10-Well Pad Online in Karnes Area in Eagle Ford Shale
DEVELOP & PRODUCE Fields in a Safe, Responsible, Timely & Cost Effective Manner	✓ Achieved Record-Low Drilling & Completions Costs in Both Eagle Ford Shale & Kaybob Duvernay
ACHIEVE & MAINTAIN a Sustainable, Diverse & Price Advantaged Oil-Weighted Portfolio	✓ Maintained Corporate Liquids-Weighting at 59% ✓ ~$68/BBL Oil Sold Realized Price ✓ ~3,000 Undeveloped Oil-Weighted Locations in Eagle Ford Shale & Kaybob Duvernay

Driving High Cash Margins With a Diversified Portfolio





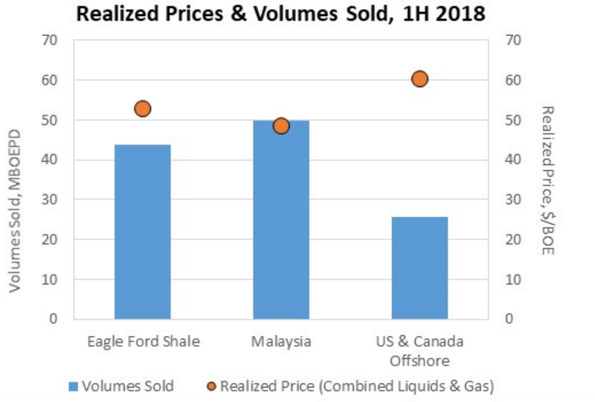
*MCO = Malaysian Crude Oil, See Definitions in Appendix
*LLS = Light Louisiana Sweet, See Definitions in Appendix

As of August 24, 2018

Generating Robust EBITDA

Allocating 70% of Capital to High EBITDA Assets

- Eagle Ford Shale
- Kikeh DTU Gas Lift
- Dalmatian Subsea Pump
- Samurai Success Evaluation



PORTFOLIO REVIEW

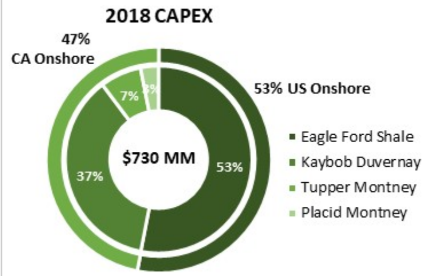
Low-Cost North America Onshore Assets

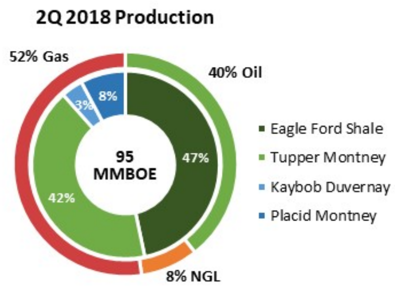
Eagle Ford Shale
- ~125,000 Net Acres, ~905 Wells Online*
- ~2,000 Remaining Locations**
- Premium LLS Pricing
- "Big Data" Focus

Kaybob Duvernay
- ~140,000 Net Acres, ~70 Wells Online*
- ~1,100 Remaining Locations**
- Successfully Lowering Cost While Delineating the Play

Tupper Montney
- ~100,000 Net Acres, 245 Wells Online*
- ~1,200 Remaining Locations**
- Aggressive Hedging & Price Diversity Program
- 14 TCF Net Resource
- Leading Low-Cost Operator

**Operated & Non-Operated as of June 30, 2018*
***Remaining Locations As of December 31, 2017 – See Appendix*





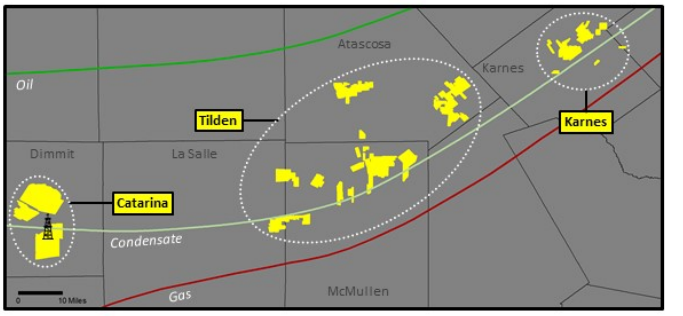
Producing Consistent Results in the Eagle Ford Shale

Operated Well Delivery – 45 Wells Online FY 2018

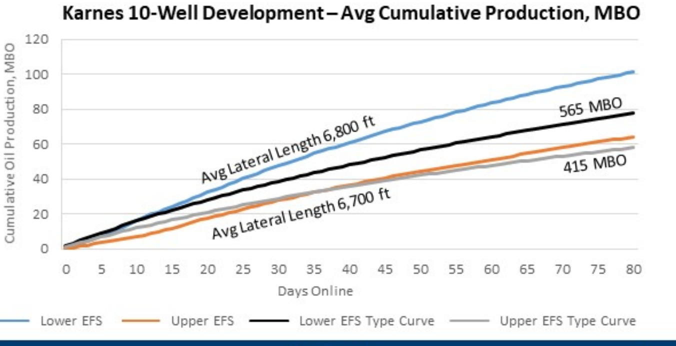
- 26 Wells Online 2Q 18 vs Guide of 22 Wells
  - 10-Well Pad in Karnes – Avg IP30 1,750 BOEPD
    - Co-Development of Lower & Upper Eagle Ford Shale Wells
    - Testing Lower Eagle Ford Shale Stagger Targets
  - 10 Wells in Catarina – Avg IP30 1,000 BOEPD (6 LEFS)
    - 8 Lower Eagle Ford Shale & 2 Upper Eagle Ford Shale Wells
  - 6 Wells in Tilden – Avg IP30 925 BOEPD
    - 6 Lower Eagle Ford Shale – 2 Wells had Avg IP30s 60% Higher than Highest Previous Tilden Yearly Avg Due to Optimized Completions
- 9 Wells Online 3Q 18 in Catarina
- 4 Wells Online 4Q 18 in Catarina

Improved Drilling Performance

- 2Q 18 Drilling Cost per Foot $87 – 27% Decrease vs 1Q 18
- 2Q 18 Completion $/CLAT $645 – 8% Decrease vs 1Q 18



Karnes 10-Well Development – Avg Cumulative Production, MBO

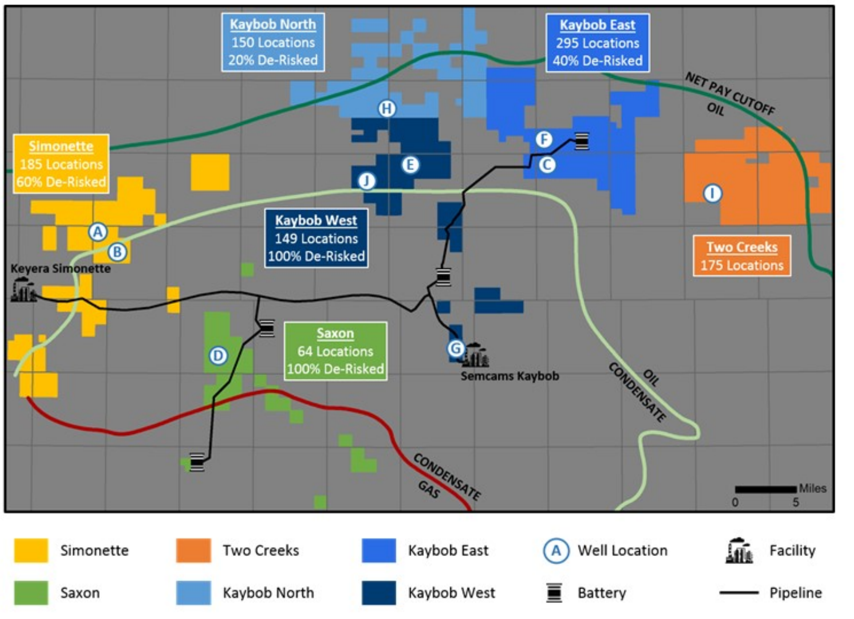


Growing the Kaybob Duvernay

Operated Well Delivery

- Current Plan – 25 Drill + 25 Complete + 27 Online

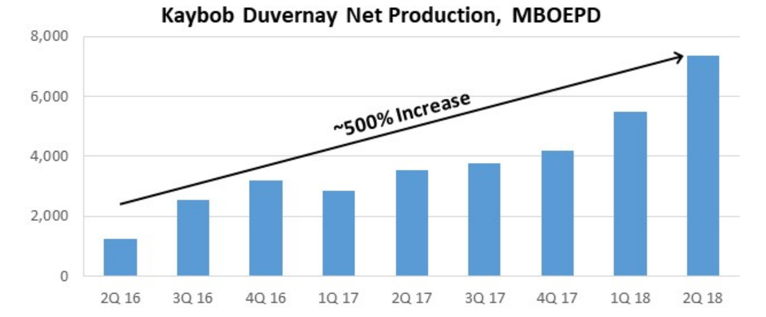
	Location	Pad	Wells	Window	Online
✓	A	01-12	1	Oil	1Q 2018
✓	B	15-16	2	Oil	1Q 2018
✓	C	12-29	2	Oil	1Q 2018
✓	D	16-03	3	Condensate	1Q 2018
✓	E	03-33	4	Oil	2Q 2018
✓	F	16-06	2	Oil	3Q 2018
✓	G	11-14	5	Condensate	3Q 2018
✓	H	16-18	3	Oil	3Q 2018
	I	04-21	1	Oil	4Q 2018
	J	16-14	4	Oil	4Q 2018
	Total Online		**27**		



Continuing Strong Execution in the Kaybob Duvernay

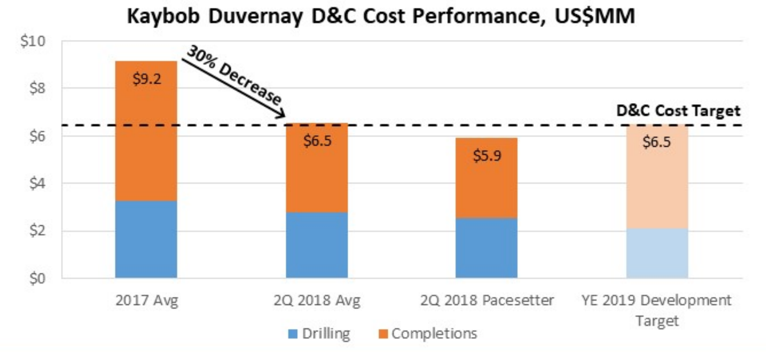
Substantial Production Growth

- Increased Kaybob Production 35% from 1Q 18 to 2Q 18, 108% Y-O-Y
- Drilled Longer Laterals, Nearly Doubled in Length
- Continued to Optimize Completions
- Switched from Rod Pumps to Gas Lift



Significant Well Cost Reductions

- Achieved 2019 D&C Target of US$6.5 MM in 2Q 18
- Delivered US$5.9 MM Pacesetter Well
  - Increased Rotary Steerable Reliability, > 100% Increase in Rate of Penetration
  - Improved Wellbore Trajectory Design
  - Optimized Completion Designs
  - Increased Frac Efficiency & Decreased Water Costs



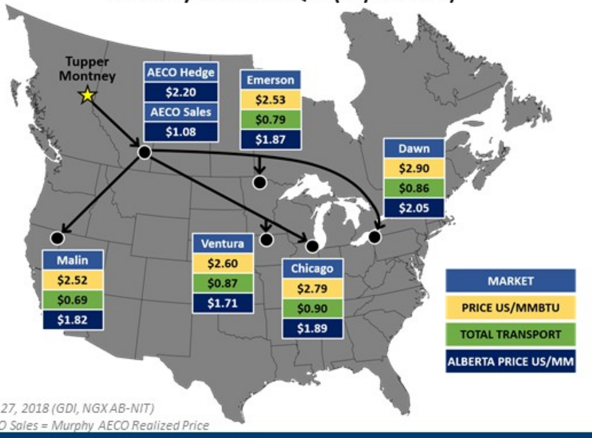
Delivering Low Cost Production in Tupper Montney

Operated Well Delivery
- 5 Wells Online 2Q 18, Avg EUR ~18 BCF

Successful AECO Price Mitigation
- AECO Daily Spot Down 43% vs MUR Realizations Down 16% (2Q 18 vs 1Q 18)
- Realized Price 3Q 18 QTD US$1.65 [C$2.14*]/MMBTU vs Daily Spot QTD of US$0.87 [C$1.13]/MMBTU AECO
  - US$1.65 ÷ 0.77 Exchange Rate = C$2.14 - C$0.27 = C$1.87/MMBTU (Netback 3Q 18 QTD)

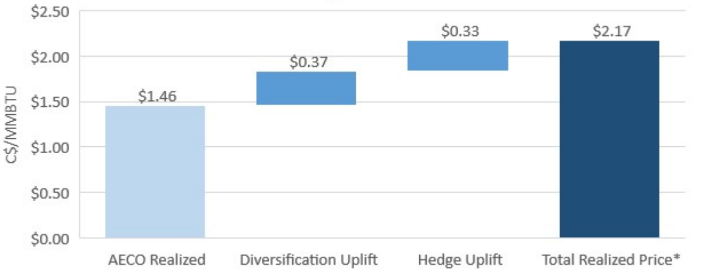
**Excluding C$0.27 Transportation Cost*

Montney Gas Prices QTD (US/MMBTU)



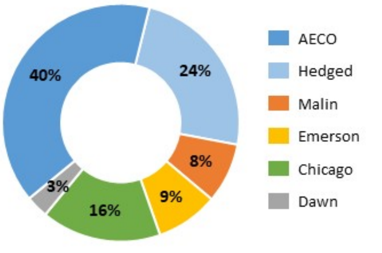
Aug 27, 2018 (GDI, NGX AB-NIT)
AECO Sales = Murphy AECO Realized Price

1H 2018 Avg Realized Price



**Excluding C$0.27 Transportation Cost*

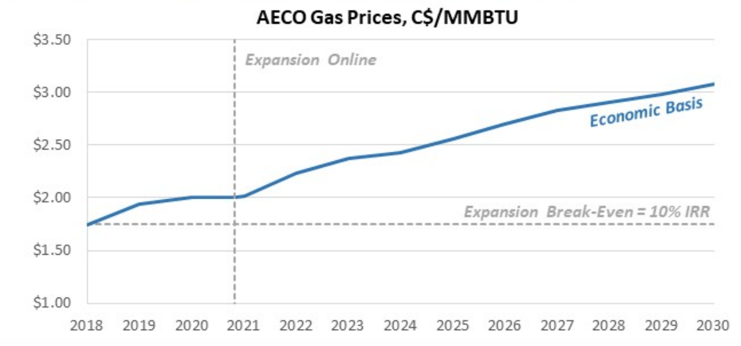
Mitigating AECO Exposure – 2018 Montney Natural Gas Sales

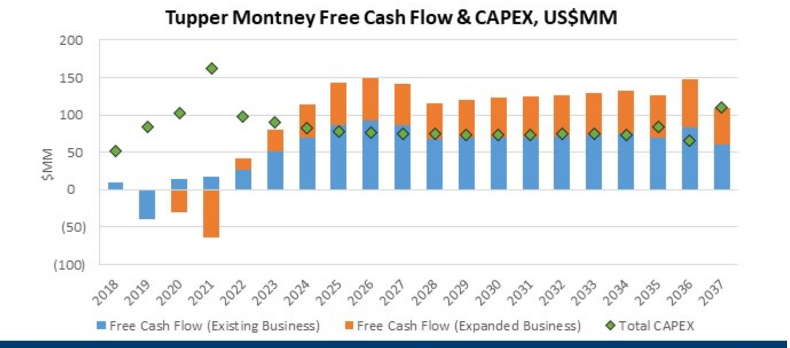


Generating Free Cash Flow from Long-Term Project

Long-Term Expansion Project Approved 2Q 18

- Additional 200 MMCFD, Online 2020 – Up to 500 MMCFD
- Adds Estimated 400+ BCF Reserves
- Break-Even ~C$1.75/MCF AECO (10% IRR)
- Highly Economic, > 25% IRR
- Flexible Capital Program
- Leads to Net Income & Free Cash Providing Business





Executing in Global Offshore

Malaysia

Sabah – Kikeh
- DTU Gas Lift Project 95% Complete, Online 3Q 18

Sarawak – South Acis
- Mobilized Jack-Up Rig for 3-Well Infill Drilling Campaign

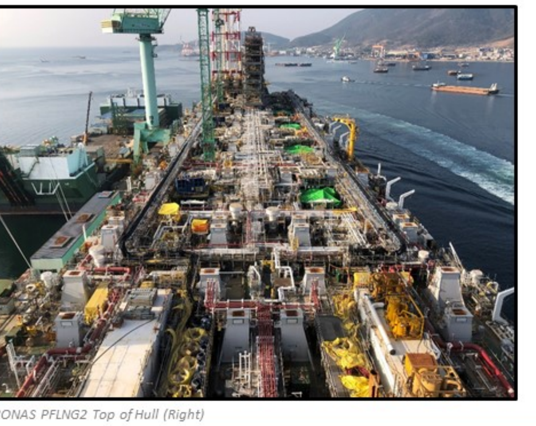
Block H
- FLNG Project on Track, Targeting First Production in 2020

Vietnam

Block 15-01/05
- Received Full Approval to Increase WI to 40%, Assumed Operatorship
- Progressing LDV Field Development Plan, LDV Development Team In Place

Gulf of Mexico

- Medusa SS 5 Well Online 2Q 18
- Beat 2Q 18 Production Guidance by ~1,700 BOEPD – Fields Outperformed
- Dalmatian Pump On Track, Online 4Q 18



Photos: Dalmatian Pump Module Testing (Left) & PETRONAS PFLNG2 Top of Hull (Right)

EXPLORATION REVIEW

Returning to Global Exploration

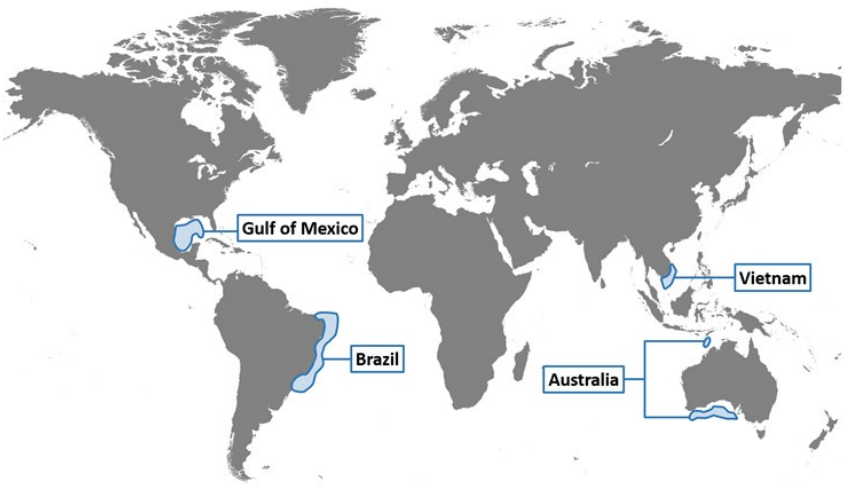
New Exploration Team Focus

- Target ~35% Working Interest
- No 100% New Entry Blocks
- Partner with Proven Explorers
- > 30% Full Cycle Return at Mean Risked Volumes
- F&D < $15
- Near Existing Discoveries/Fields
- Better Data, Wide Azimuth (WAz) Seismic

	2018	2019	2020	2021	2022
United States	 				
Mexico	 *				
Brazil					
Australia					
Vietnam	 *				
Malaysia					

*Commitment Well

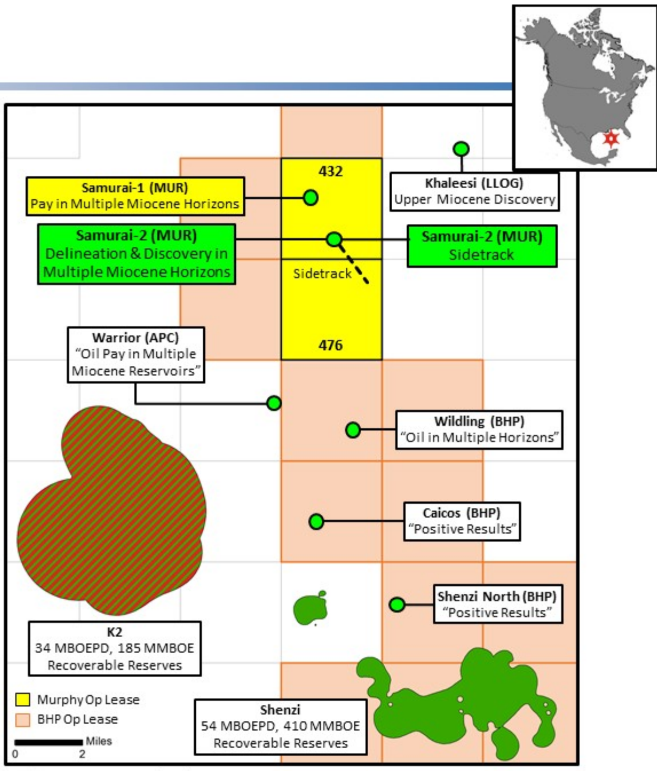
Exploration Focus Areas



Achieving Successful Exploration

Gulf of Mexico Samurai Appraisal (GC432 #2)

- Murphy 50% WI, Operator, BHP 50% WI
- Spud 2Q 2018
- Well TD 32,080 ft
- Encountered > 150 ft Total Pay
  - Delineated Existing Pay Zones from Samurai-1
  - Hydrocarbons Discovered in New Pay Zones
- Discovered Gross Resources > 75 MMBOE, Above Pre-Drill Estimates
- Drilling Appraisal Sidetrack of Samurai-2 Well



Field Data Source: WoodMackenzie

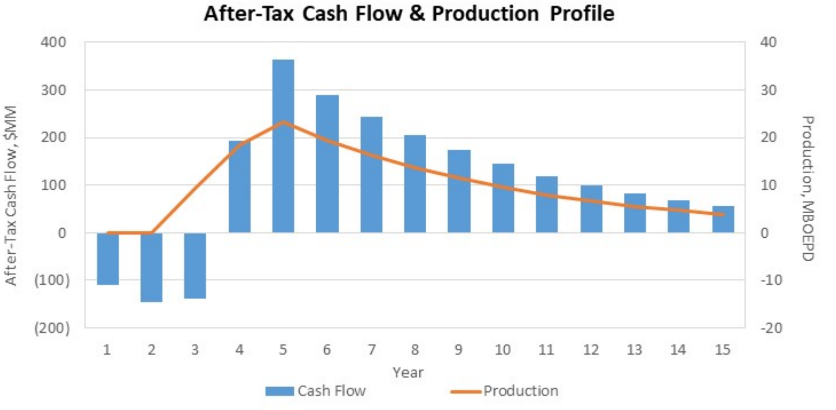
Developing Gulf of Mexico Tie-Backs

Development Summary

- Tie-Back to Host Facility within 20 Miles
- ~18 Month to Complete Tie-Back
- 4 Wells/8 Completions
- Development CAPEX $660 MM
  - Drilling & Completion $410 MM
  - Facilities $250 MM

Economic Metrics

- Gross F&D Cost $8.80/BOE
- OPEX $10/BOE
- IRR 35% to 40%
- Break-Even < $32/BOE
- Payout ~4 Years
- 15 Year Cumulative Cash Flow ~$2 BN



	Year 1				Year 2			
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Sanction Development								
Detailed Design								
Facilities & Construction								
Drilling & Completions								
First Oil								

NOTE: Economics Represent a Generic Gulf of Mexico Tie-Back

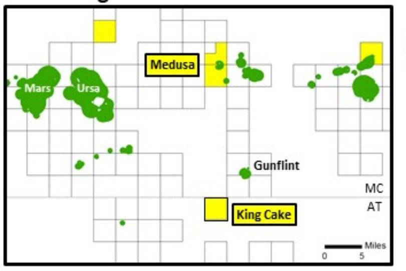
Gaining Momentum in Strategic Exploration

GOM King Cake Prospect (AT23 #1)
- Murphy 31.5% WI, Operator
- Expected Spud 3Q 18
- Gross Resource Potential – 50 MMBOE (Mean) to 100 MMBOE (Upside)
- Net Well Cost ~$22 MM

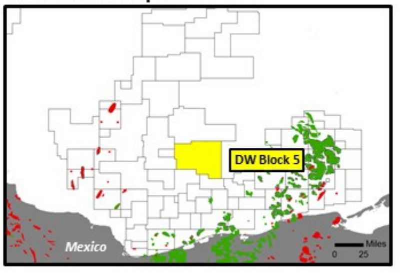
Cuu Long Basin LDT Prospect (Block 15-1/05)
- Murphy 40% WI, Operator
- Expected Spud 4Q 18
- Gross Resource Potential – 30 MMBOE (Mean) to 250 MMBOE (Upside)
- Net Well Cost ~$19 MM

Mexico Palenque Prospect (DW Block 5)
- Murphy 30% WI, Operator
- Exploration Plan Approved, Tendering for Rig
- Expected Spud 4Q 18
- Gross Resource Potential – 200 MMBOE (Mean) to 500 MMBOE (Upside)
- Net Well Cost ~$15 MM

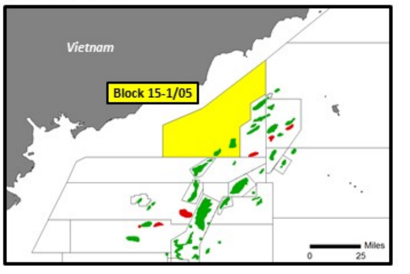
GOM King Cake



Mexico Palenque



Vietnam LDT



Brazil Exploration Update

Renewed Exploration Portfolio with Low-Cost Entry & Long-Term Opportunities in 6 Blocks

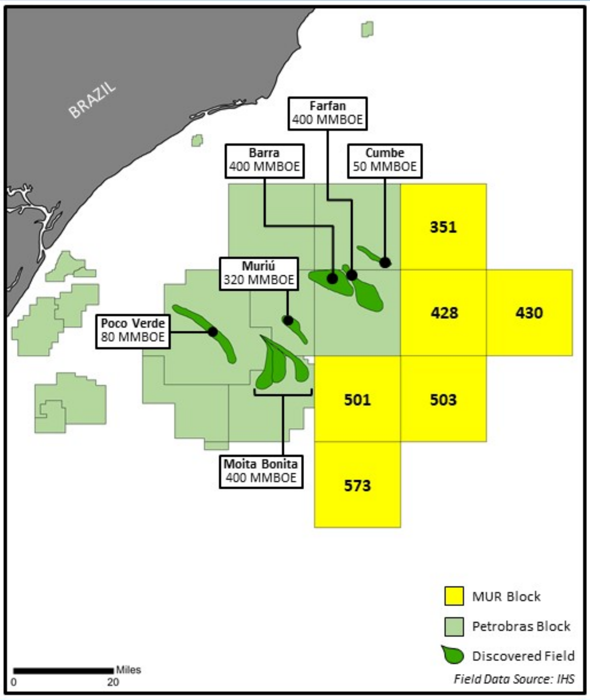
- Progressing 2018 Seismic Program

Farm-In to QGEP's Sergipe-Alagoas Blocks

- Secured Blocks 351 & 428
- Murphy 20%, ExxonMobil 50% (Op), QGEP 30%
- No Well Commitment

Same Co-Venture Group Successful in Bid Rounds

- Blocks 501 & 503 – Round 14
- Blocks 430 & 573 – Round 15
- No Well Commitment



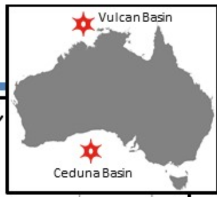
Australia Exploration Update

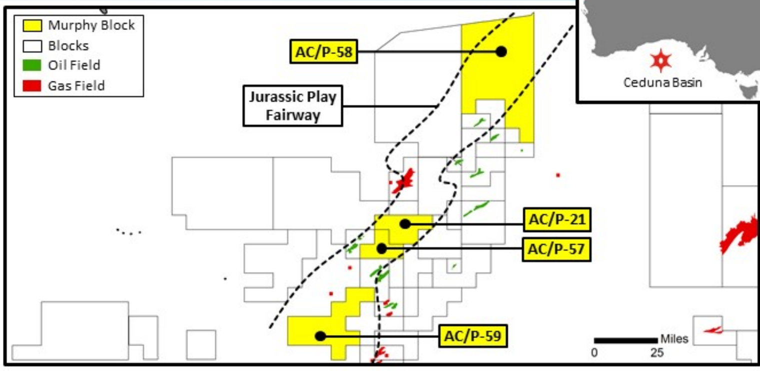
Vulcan Basin

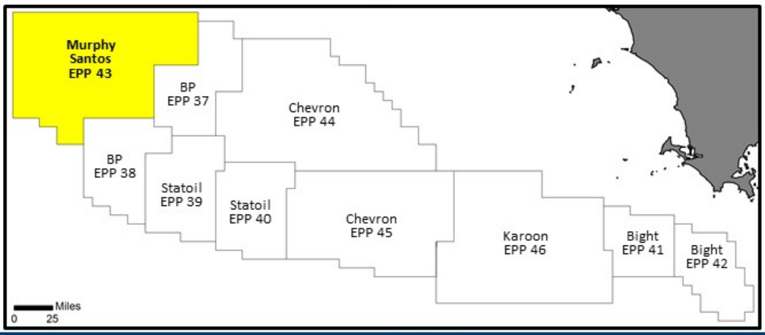
- Murphy 40% – 60% WI, Operator
- Expected Spud 2019 & 2021
- Identifying Multiple Prospects, Up to 200 MMBOE Gross Recoverable Resource Potential
- Evaluating 3D Seismic Data
- No Well Commitment

Ceduna Basin

- Murphy 50% WI, Operator
- Maturing 5 Leads with 300+ MMBBL Recoverable Resource Potential
- 50 Leads Identified on New 3D Seismic
- Frontier Basin with Offset First Drilling in 2019
- No Well Commitment







Positioning Company for Long-Term Value Creation

Delivering the 2018 Plan

Achieving Strong EBITDA Margins

Returning to Successful Offshore Exploration

Executing High-Return Offshore Projects

Driving Costs Lower in North American Onshore

Funding Operational Success in Kaybob Duvernay & Offshore

Continuing to Return Cash to Shareholders with Current Dividend Policy

Maintaining 4-Year Production CAGR of 10-15% within Cash Flow

APPENDIX

Appendix

- Non-GAAP Reconciliation
- Abbreviations
- Guidance
- Hedging Positions
- 2017 Overview & Reserves

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 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	Three Months Ended – June 30, 2018	Three Months Ended – June 30, 2017
Net income (loss)	45.5	(17.6)
Discontinued operations loss	0.4	0.2
Mark-to-market (gain) loss on crude oil derivate contracts	10.1	(14.7)
Foreign exchange losses	7.1	31.1
Deferred tax on undistributed foreign earnings	-	5.8
Tax benefits on investments in foreign areas	-	(21.1)
Oil Insurance Limited dividends	-	(2.8)
Adjusted Income (loss) (Non-GAAP)	**63.1**	**(19.1)**

Non-GAAP Reconciliation

EBITDA and EBITDAX

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

$ Millions	**Three Months Ended – June 30, 2018**	**Three Months Ended – June 30, 2017**
Net income (loss)	45.5	(17.6)
Discontinued operations loss	0.4	0.2
Income tax expense (benefit)	36.4	(4.5)
Interest expense, net	44.7	45.1
DD&A expense	238.0	235.0
Consolidated EBITDA (Non-GAAP)*	**365.0**	**258.2**
Exploration expense	19.2	20.2
Consolidated EBITDAX (Non-GAAP)*	**384.2**	**278.4**

**EBITDA and EBITDAX for the three months ended June 30, 2018 included certain pretax items that decreased both amounts by $36 million*

Non-GAAP Reconciliation

ADJUSTED EBITDAX

Murphy defines Adjusted EBITDAX as income from continuing operations 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.

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	Three Months Ended – June 30, 2018	Three Months Ended – June 30, 2017
Consolidated EBITDAX (Non-GAAP)	384.2	278.4
Mark-to-market (gain) loss on crude oil derivative contracts	12.7	(22.6)
Foreign exchange loss	12.2	35.9
Accretion of asset retirement obligations	11.0	10.4
Other	(0.2)	1.3
Adjusted EBITDAX (Non-GAAP)	**419.9**	**303.4**
Total barrels of oil equivalents sold (boe)	15,532.0	14,578.5
Adjusted EBITDAX per boe (Non-GAAP)	**27.03**	**20.81**

Abbreviations

BBL: barrels (equal to 42 US gallons)
BCF: billions of cubic feet
BCFE: billion cubic feet equivalent
BN: billions
BOE: barrels of oil equivalent (1 barrel of oil or 6000 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
FLNG: floating liquefied natural gas
G&A: general and administrative expenses
GOM: Gulf of Mexico
HCPV: hydrocarbon pore volume
JV: joint venture
LOE: lease operating expense
LLS: Light Louisiana Sweet (a grade of crude oil, includes pricing for GOM and EFS)
LNG: liquefied natural gas
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
MMCFEPD: million cubic feet equivalent per day
MMSTB: million stock barrels
MCO: Malaysia Crude Official Selling Price, differential to average monthly calendar price of Platts Dated Brent for delivery month
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)

Guidance – 3Q 18

Guidance 3Q	3Q 2018 Liquids (BOPD)	3Q 2018 Gas (MCFD)
3Q Production:		
US – Eagle Ford Shale	41,775	31,650
Gulf of Mexico	15,625	14,100
Canada – Tupper Montney	–	234,500
Kaybob Duvernay & Placid Montney	7,200	32,000
Offshore	5,000	–
Malaysia – Sarawak	11,900	99,250
Block K/Brunei	16,800	3,700
3Q Production Volume (BOEPD)	166,500 – 168,500	
3Q Sales Volume (BOEPD)	164,000 – 166,000	
3Q Exploration Expense ($MM)	$32.0	
Full Year 2018 Production (BOEPD)	168,500 – 170,500	
Full Year 2018 Capex ($BN)	$1.18	
3Q Expected Realized Prices ($/BBL)	Malaysia – Block K Oil	$66.60
	Sarawak Oil	$61.70
($/MCF)	Sarawak Gas	$4.00

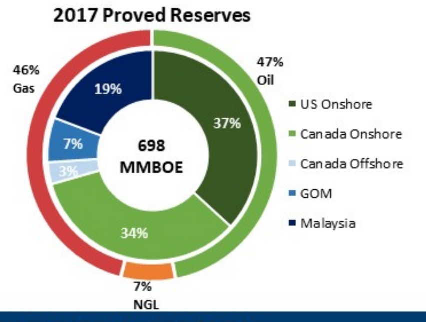
2018 Hedging Positions

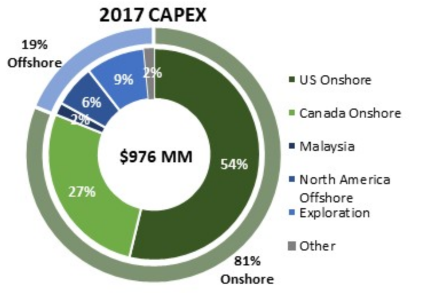
Area	Commodity	Type	Volumes (BOPD)	Price (USD/BBL)	Start Date	End Date
United States	WTI	Fixed Price Derivative Swap	21,000	$54.88	7/1/2018	12/31/2018

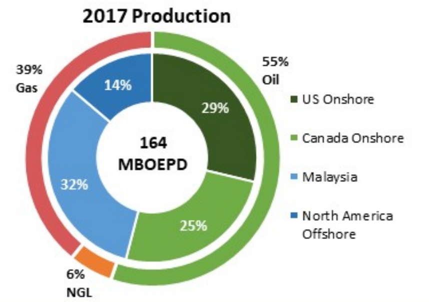
Area	Commodity	Type	Volumes (MMCFD)	Price (MCF)	Start Date	End Date
Montney	Natural Gas	Fixed Price Forward Sales	59	C$2.81	7/1/2018	12/31/2020

2017 Asset Overview

At December 31, 2017	Crude Oil	NGLs	Natural Gas	Total
Proved Developed Reserves:	(Millions of Barrels)		(Billions of Cubic Feet)	(Millions of Barrels Equivalent)
United States	126.3	23.3	127.7	170.9
Canada	21.9	1.0	547.0	114.1
Malaysia	37.3	0.3	144.6	61.7
Total Proved Developed Reserves	**185.5**	**24.6**	**819.3**	**346.7**
Proved Undeveloped Reserves:				
United States	98.4	19.7	95.6	134.0
Canada	29.6	4.6	665.5	145.1
Malaysia	14.6	-	346.7	72.4
Total Proved Undeveloped Reserves	**142.6**	**24.3**	**1,107.8**	**351.5**
Total Proved Reserves	**328.1**	**48.9**	**1,927.1**	**698.2**

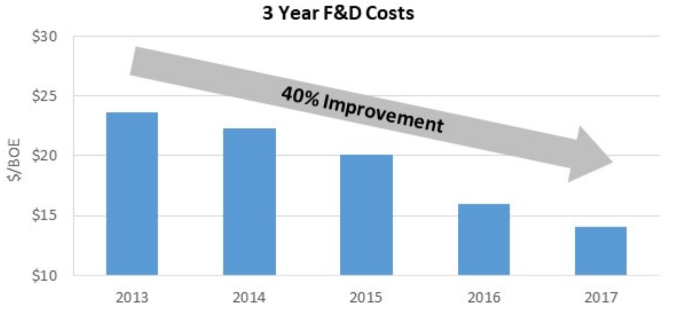


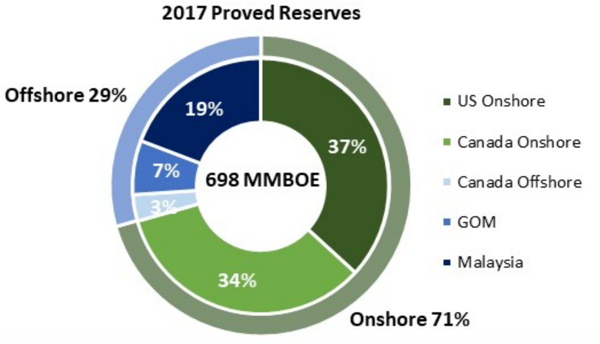


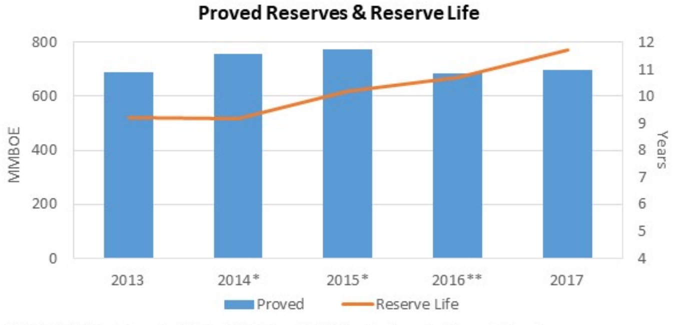


Increasing Reserves & Lowering F&D Costs in 2017

- Maintaining High-Margin, Oil-Weighted Portfolio
- Organic Reserves Replacement 113%
- Total Reserves Replacement 123%
- 1 Year F&D Costs of $13.09/BOE
- 3 Year Cumulative F&D Costs of $14.08/BOE
- Reserve Life Index 11.7 Years, Increased from 10.7 Years







*2014 & 2015 Include Impact of Malaysia Sell-Down, **2016 Includes Impact of Syncrude Divestiture

Maintaining Financial Discipline

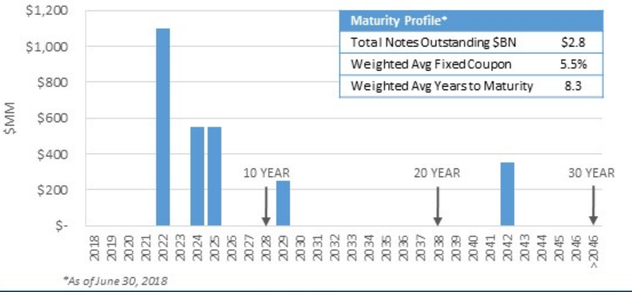
Adjustments to 2Q 18 Earnings
- Mark-to-Market Loss on Crude Oil Contracts $10 MM, After Tax
- Foreign Exchange Loss $7 MM, After Tax

Balance Sheet
- Low Leverage (2.0x Total Debt/EBITDA) with ~$2 BN Liquidity, No Near-Term Debt Maturities
- $2.8 BN Total Debt (Excluding Capital Lease)
- $900 MM Cash & Cash Equivalents
- 38% Total Debt / Total Capitalization
- 30% Net Debt / Total Capitalization

Hedge Positions June 30, 2018
- 21,000 BPD at US$54.88/BBL, Bal 2018
- 59 MMCFD at AECO C$2.81/MCF, July 1, 2018 – Dec 31, 2020

$MM (Except per Share)	2Q 18	2Q 17
Continuing Operations		
Income (Loss)	46	(17)
$/Diluted Share	0.26	(0.10)
Adjusted Earnings		
Adjusted Earnings (Loss)	63	(19)
$/Diluted Share	0.36	(0.11)

Note Maturity Profile



Maturity Profile*	
Total Notes Outstanding $BN	$2.8
Weighted Avg Fixed Coupon	5.5%
Weighted Avg Years to Maturity	8.3

*As of June 30, 2018

Expecting Cash Flow, CAPEX & Dividend Parity for FY 2018

1H 2018 Adversely Affected By:

- $35 MM One-Time Withholding Tax Payment on Funds Repatriated from Canada
- CAPEX Accrued in 2017 but Paid in 2018 Totaled $39 MM, Exceeding 2018 CAPEX Accrued but not Paid by $15 MM

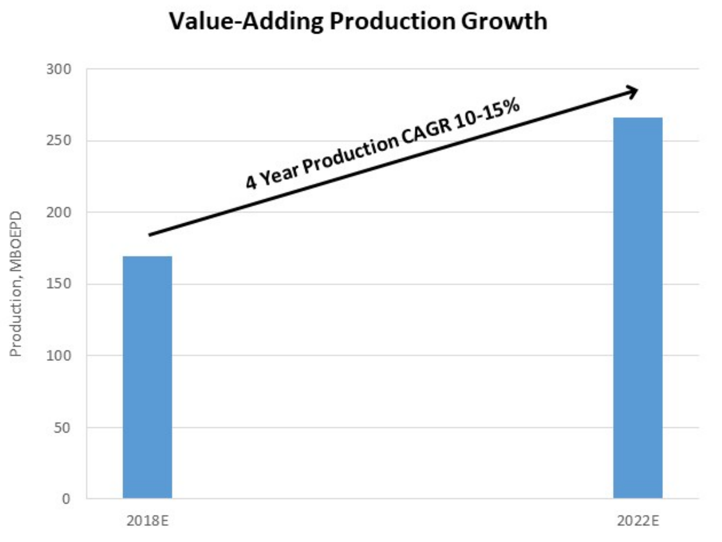
Results:

- Net Result is June 30, 2018 Cash Decreased by $64 MM from December 31, 2017
- Higher Price Expectations, as Evidenced by Forward Curve, & Lower 2H 2018 CAPEX Should Result in Rebuild of Cash to Near YE 2017 Levels, Excluding One-Time Withholding Tax Payment

Condensed Cash Flow Statement	$MM
Beginning Cash at December 31, 2017	964.9
Cash Provided by Continuing Operations	624.5
Cash Used in Investing Activities	614.5
Cash Dividends Paid	86.5
Other Cash Sources (Net)	12.9
Ending Cash at June 30, 2018	901.3

Long-Term Strategy Drives Profitable Growth

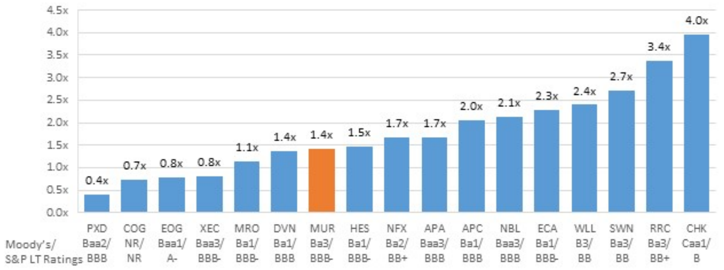
- Measured, Oil-Weighted Production Growth Within Cash Flow
- Plan Returns Over $800 MM to Shareholders with Current Dividend Policy
- Plan Delivers ~$500 MM Free Cash Flow, In Addition to Dividend
- Doubling EBITDA by 2022



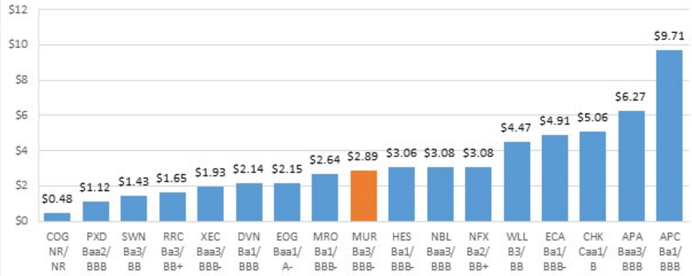
Guidance Assumes WTI $52/BBL & HH $3/MCF, Escalated at 5%

Credit Metrics vs E&P Peers – 2Q 2018

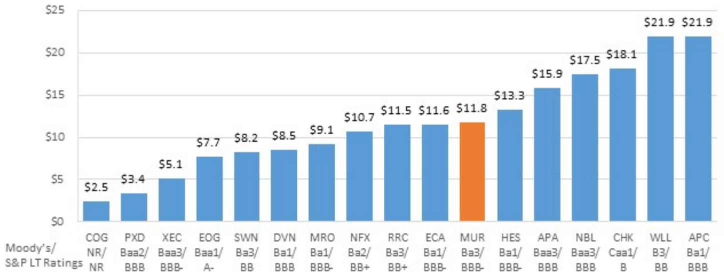
2Q 2018 Net Debt / Adj EBITDAX (LTM)



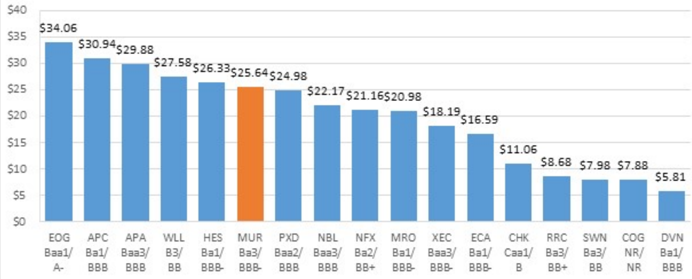
2Q 2018 Net Debt / 2017 Proved Reserves* ($/BOE)



2Q 2018 Net Debt / Production ($000/BOEPD)



2Q 2018 Adj EBITDAX / Production ($/BOE)



*Source: Bloomberg, Company Filings as of 6/30/18, *As of 12/31/17, NR = Not Rated, Moody's Credit Rating is Sr. Unsecured Debt Rating, S&P Rating is LT Local Issuer Credit Rating*

Bloomberg Definitions

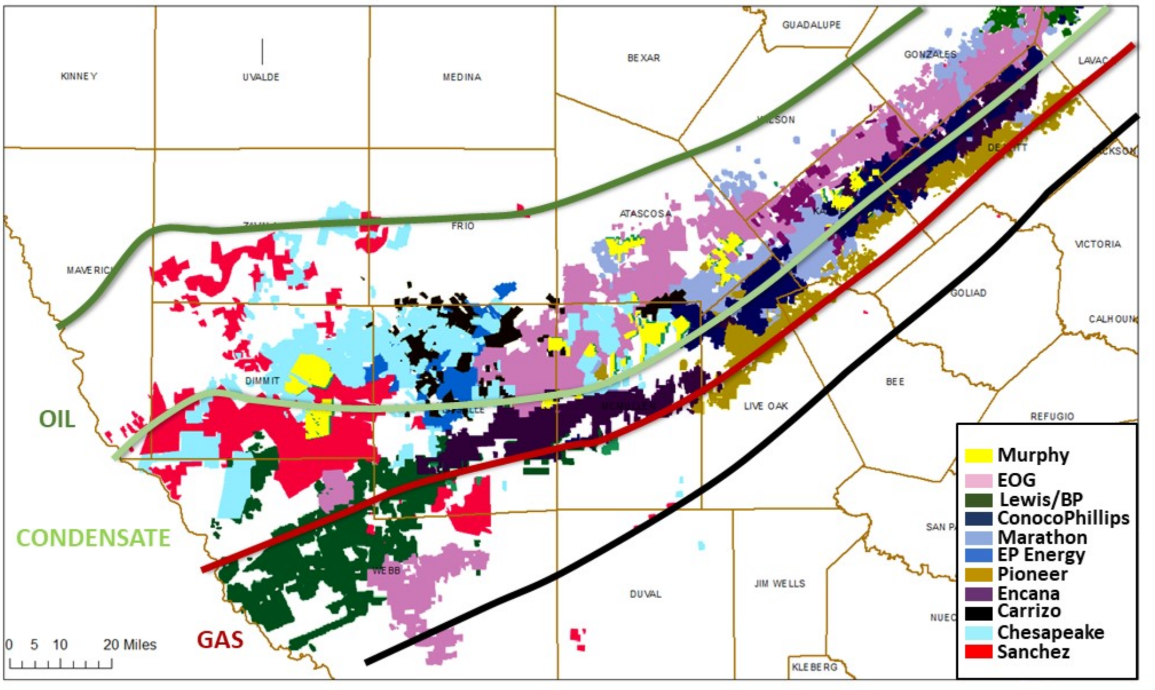
- **Net Income/BOE** = Net Income (Loss) as Reported / Total Annual Production
- **EBITDA** = Loss from Continuing Operations - Interest & Other Income + Income Tax Expense (Benefit) + Interest Expense - Interest Capitalized + DD&A
- **EBITDA/BOE** = EBITDA / Total Annual Production
- **Production Netback** = E&P Revenues/BOE - Lifting Costs/BOE (E&P Revenues are Net of Royalties and Realized Hedging Gains and Losses, BOE is Total Annual Production)
- **Lifting Costs** = Lease Operating Expenses + Severance and Ad Valorem Taxes
- **Organic Reserve Replacement** = (Revisions + Improved Recovery + Extensions & Discoveries) Proved Reserves / Total Annual Production
- **Reserve Life Index (R/P)** = YE Proved Reserves / Total Annual Production
- **Total Reserve Replacement Cost (FD&A)** = (Exploration + Development + Property Acquisition) Costs / (Revisions + Improved Recovery + Extensions/Discoveries + Purchases) Proved Reserves
- **Production Netback** = E&P Revenue per BOE - Lifting Cost (Production Cost) per BOE
- **Recycle Ratio** = Production Netback per BOE / Reserve Replacement Cost per BOE (F&D Cost/BOE)
- **EBITDAX** = Loss from Continuing Operations - Interest & Other Income + Income Tax Expense (Benefit) + Interest Expense - Interest Capitalized + DD&A + Exploration Expense
- **EBITDAX/BOE** = EBITDAX / Total Annual Production
- **Net Debt/Adjusted EBITDA** = Interest-bearing liabilities, minus cash or cash equivalents / EBTIDA Excluding the Impact of Abnormal Items
- **Adjusted EBITDAX** = EBITDAX Excluding the Impact of Abnormal Items
- **Adjusted EBITDA** = EBITDA Excluding the Impact of Abnormal Items
  - ***Abnormal Items*** Include: realized investment gains or losses, restructuring charges, non-recurring charges/gains, unusual charges/gains, special charges/gains, reserve charges, writedowns of assets, spin-off/sell-off expenses, merger expenses, acquisition charges, sale of subsidiary expenses, forgiveness of debt, writedown of goodwill and acquired research and development costs

NA Onshore Running Room

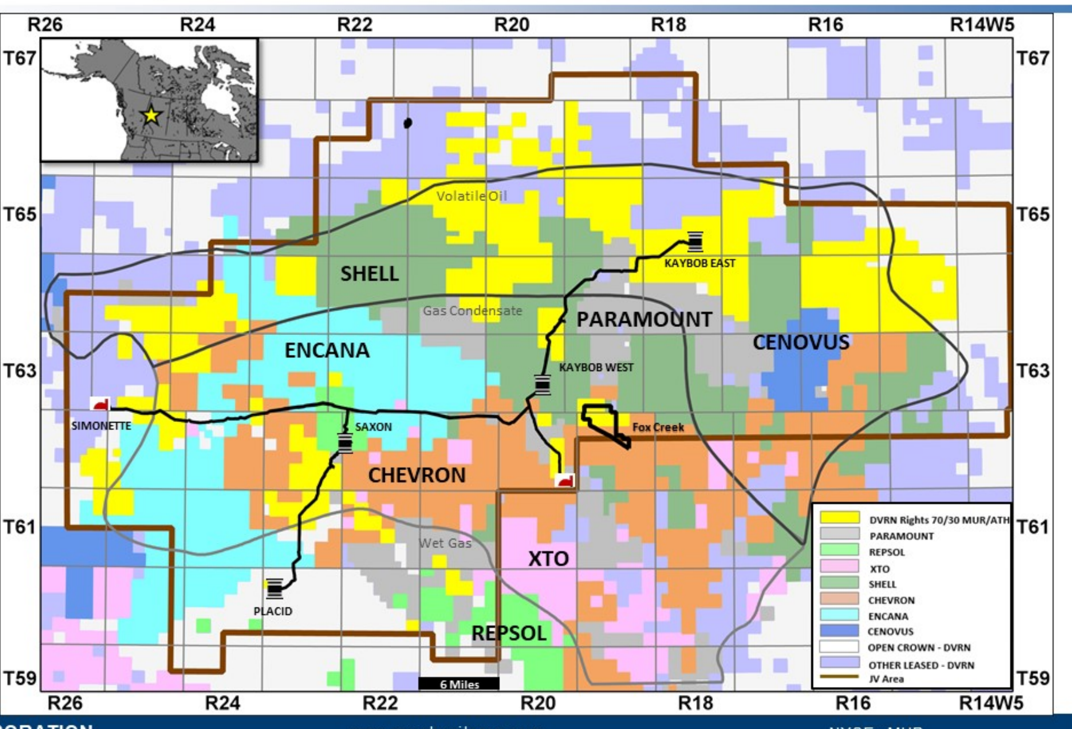
	Area	Net Acres	PDP Wells	Reservoir	Remaining Wells	Spacing (Acres)	Inter-Well Spacing (ft)	Total Well Count*
NA Onshore	**Total**	**413,156**	**1,222**		**5,176**			**6,398**
Eagle Ford Shale	Karnes	10,918	274	Lower EFS	60	40	350	599
				Upper EFS	158	80	700	
				Austin Chalk	107	140	700	
	Tilden	55,639	392	Lower EFS	391	60	500	1,023
				Upper EFS	140	60	500	
				Austin Chalk	100	60	500	
	North Tilden	8,787	19	Lower EFS	54	90	500	73
	Catarina	47,194	188	Lower EFS	354	70	400	1,095
				Upper EFS	404	100	600	
				Austin Chalk	149	100	800	
Permian	Chaparral	21,750	0	Middle Spraberry	120	160	880	487
			1	Lower Spraberry	119	160	880	
			0	Wolfcamp A	120	160	880	
			2	Wolfcamp B	119	160	880	
			6	Wolfberry Vertical	-	-	-	
	Mustang Draw	8,868	0	Middle Spraberry	71	150	880	284
				Lower Spraberry	71	150	880	
				Wolfcamp A	71	150	880	
				Wolfcamp B	71	150	880	
United States	**Total**	**153,156**	**882**		**2,679**			**3,561**
Duvernay	Kaybob	25,466	56	Gas Cond	206	220	1,000	262
		114,534	-	Oil	885	220	1,000	885
Montney	Tupper	102,000	240	Montney	1,291	220	1,000	1,531
	Placid	18,000	44	Montney	115	290	1,300	159
Canada	**Total**	**260,000**	**340**		**2,497**			**2,837**

**As of December 31, 2017*

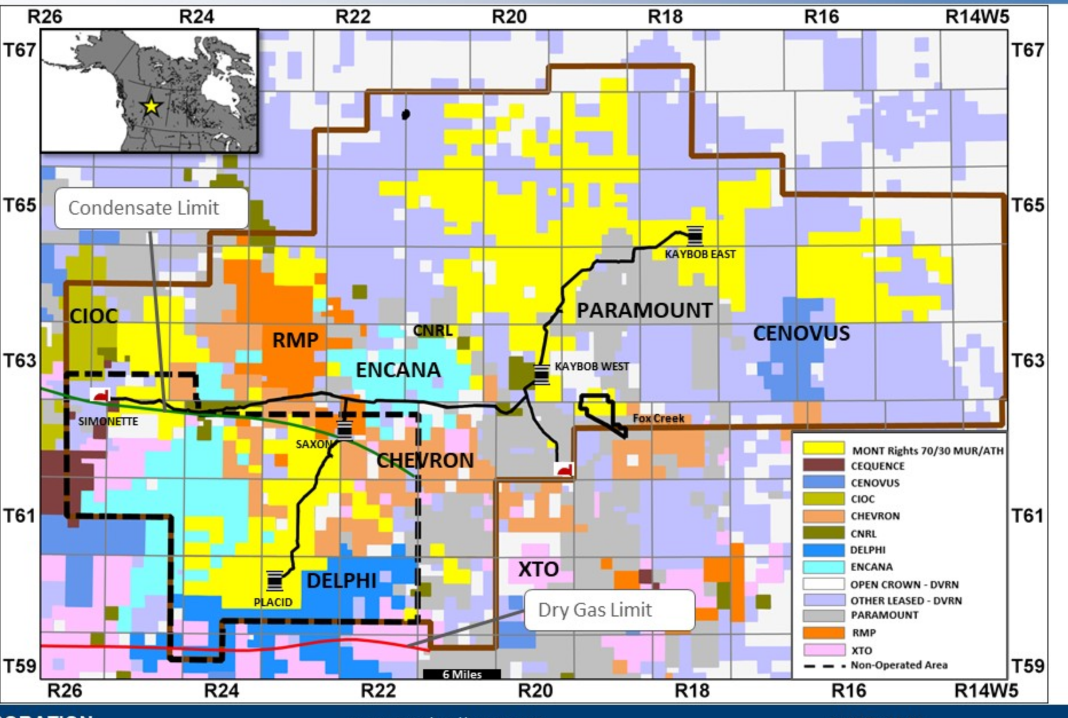
Eagle Ford Shale – Peer Acreage



Kaybob Duvernay – Peer Acreage



Placid Montney – Peer Acreage



Tupper Montney – Peer Acreage