MURPHY OIL CORPORATION

INVESTOR UPDATE

SEPTEMBER 2019

ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER

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.

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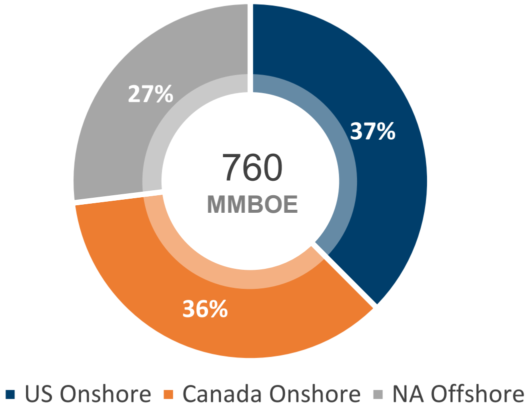
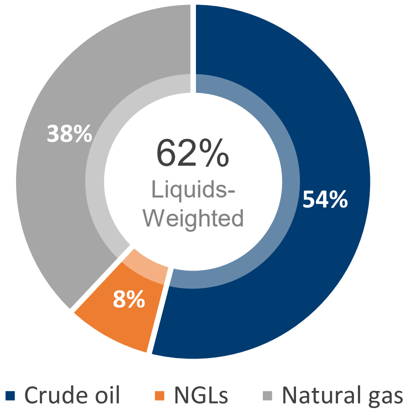
Agenda

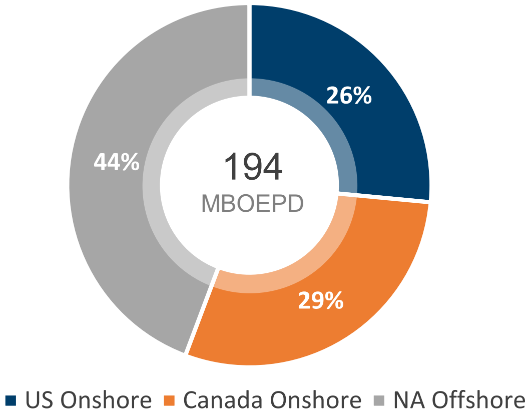
Murphy at a Glance

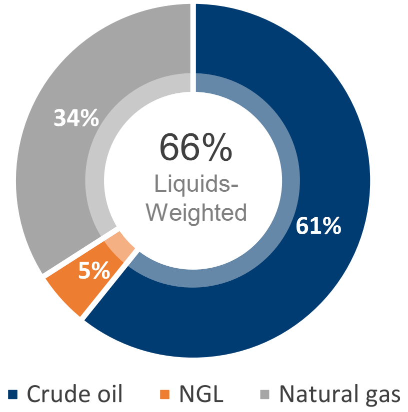
Post-Transaction Reserves*

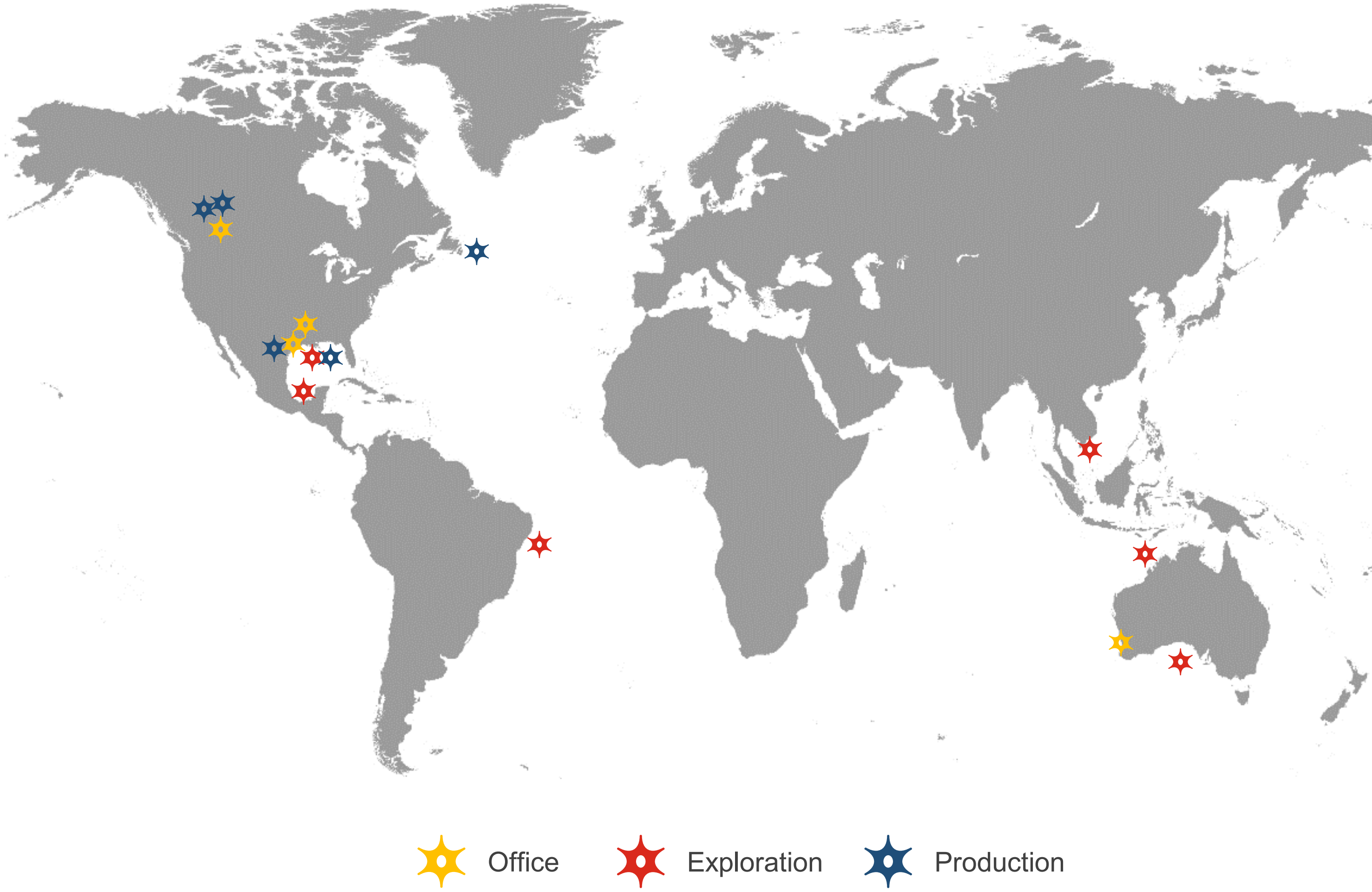




3Q 2019 Production Guidance







* *Based on internal estimates as of January 1, 2019 using year-end SEC pricing. Includes MP GOM (excluding non-controlling interest) and LLOG asset acquisitions and Malaysia divestiture, and excludes Brunei (asset held for sale).*

Value-Adding Transformation

2016
Acquired Kaybob Duvernay & Placid Montney
$206 MM

2018
Transaction with Petrobras Gulf of Mexico
$795 MM

2019
Acquired LLOG Gulf of Mexico Assets
$1.375 BN

2014 – 2015
Repositioning Portfolio Post-Spin; Streamlining Assets

2016 – 2017
Stabilizing & Rebuilding; Strengthening Balance Sheet Without Issuing Equity

2018 – 2019
Reshaping Portfolio; Growing Oil-Weighted Assets With Free Cash Flow Generation

2014
Sell-Down 30% Malaysia
$2.0 BN

2016
Divested Montney Midstream
$412 MM

2016
Divested Syncrude
$730 MM

2017
Divested Heavy Oil
$51 MM

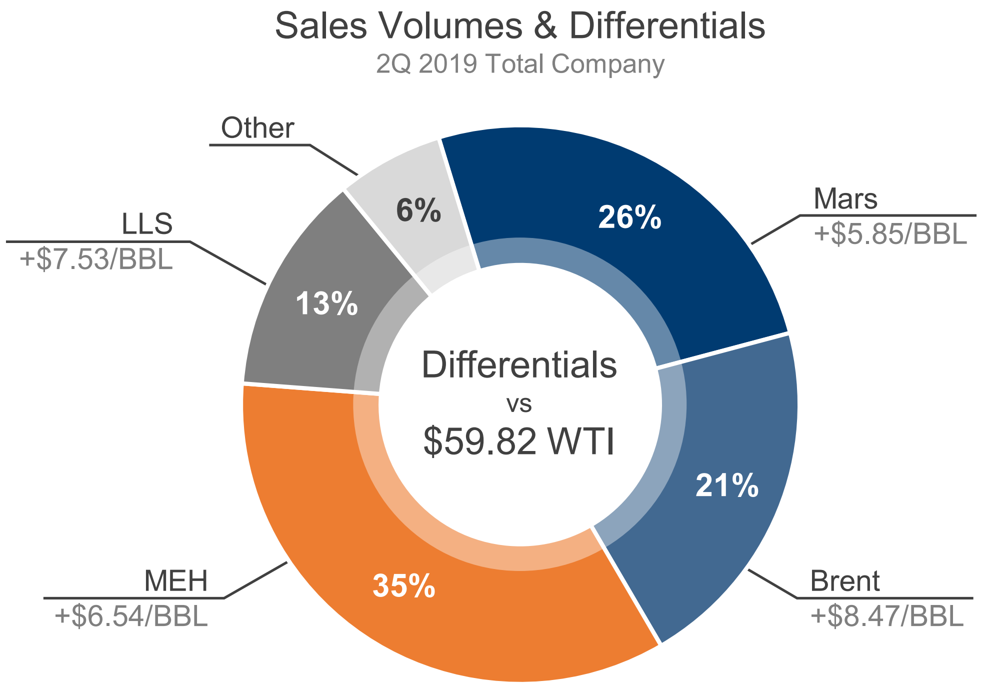
2019
Divested Malaysia
$2.127 BN

Achieving Premium Oil-Weighted Realizations

> 94,000 BBLS/Day SOLD 2Q 2019

94 % SOLD At Premium *to $59.82 WTI*

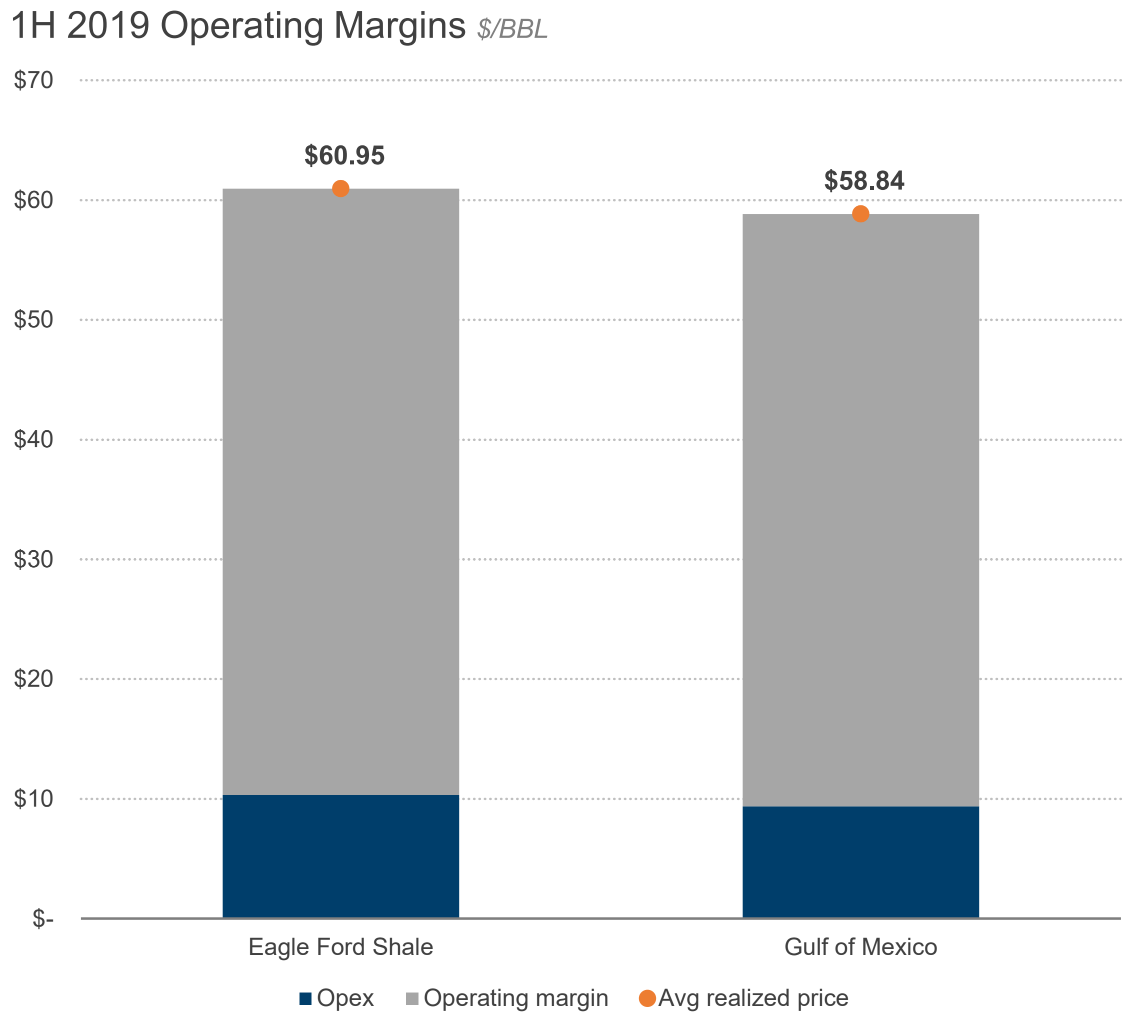
	Eagle Ford Shale	North America Offshore
Premium to WTI 2Q 2019 AFTER-TRANSPORT	>$4 /BBL	>$3 /BBL
EBITDA/BOE 2Q 2019 FIELD-LEVEL	$35 /BOE	$38 /BOE



Eagle Ford Shale and Gulf of Mexico Deliver Strong Operating Cash Flows

Achieving High Operating Margins

- Generating >$50/BBL margins
- Allocating >75% of capital to Eagle Ford Shale and Gulf of Mexico
- Operating efficiencies result in low OPEX
- Timely hedging mitigates cash flow risk



NOTE: Operating margin calculated as price realizations less operating expenses
Price realizations are net of transportation costs. WTI $57.36/BBL in 1H 2019.

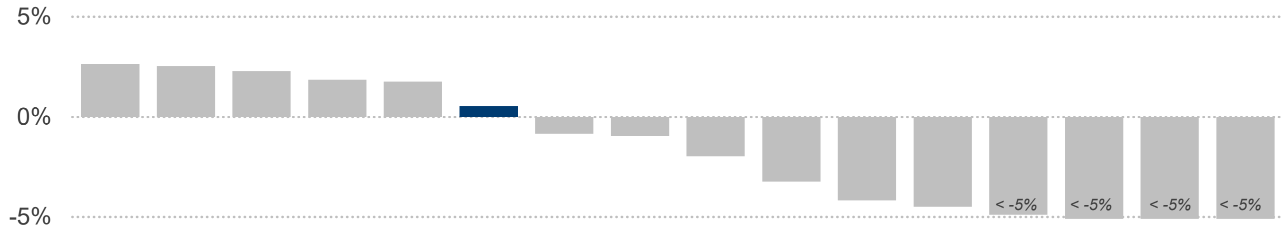
Long History of Benefitting Shareholders

> $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*

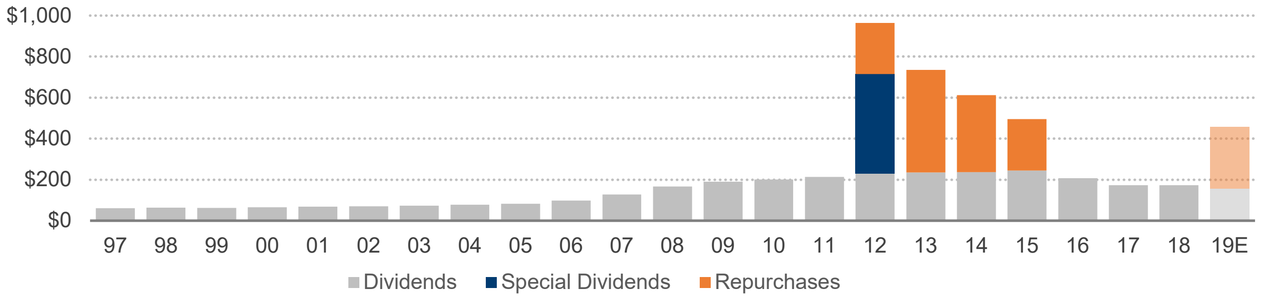


Note: FCF Yield = CFO Less Property Additions & Dry Hole Costs Divided by Market Cap (Avg. from 12/31/16 to 9/17/19)
Source: Bloomberg
Peer Group: APA, CHK, CNX, COG, DVN, ECA, HES, MRO, MTDR, NBL, RRC, SM, SWN, WLL ,XEC

Dividend + Buyback – Issuance Yield Annualized *2016 - 2019E*

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 9/17/19
Peer Group: APA, CHK, CNX, COG, DVN, ECA, HES, MRO, MTDR, NBL, RRC, SM, SWN, WLL ,XEC

Cash Paid to Shareholders $MM *1997 - 2019E*



Positioned for Investor Value Creation

> 4% Dividend Yield

Longstanding & Competitive

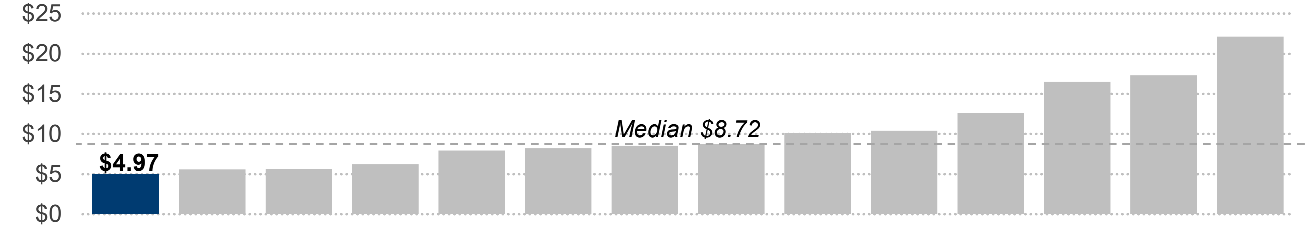
< 35% Net Debt to Cap

At July 31, 2019

< 1.4x Net Debt / EBITDAX

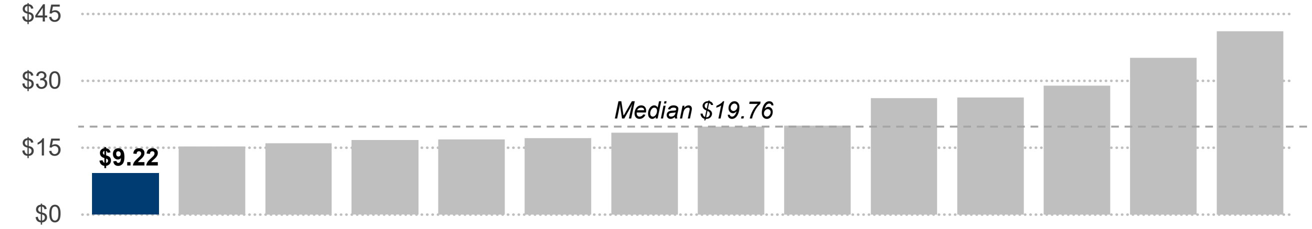
At July 31, 2019

$/BOE 1P Total Reserves



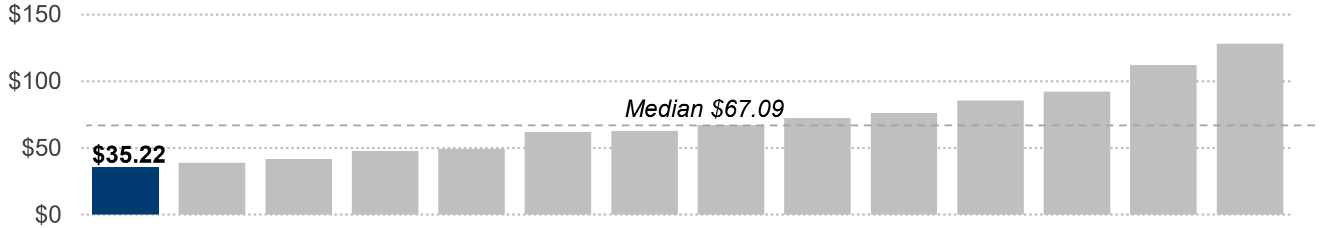
Note: Calculated based on Market Cap (9/17/2019, in $Millions) Divided by Total Proved Reserves (MMBOE, 12/31/18);
Source: FactSet
Peer Group: APA, CLR, CXO, DVN, ECA, FANG, HES, MRO, NBL, PE, PXD, WPX, XEC

$/BOE 1P Oil Reserves



Note: Calculated based on Market Cap (9/17/2019, in $Millions) Divided by Total Proved Oil Reserves (MMBO, 12/31/18);
Source: FactSet
Peer Group: APA, CLR, CXO, DVN, ECA, FANG, HES, MRO, NBL, PE, PXD, WPX, XEC

Value Per Flowing Oil Barrel



Note: Calculated based on Market Cap (9/11/2019, in $Millions) Divided by 2Q 2019 Oil Production (MBOPD)
Source: FactSet
Peer Group: APA, CLR, CXO, DVN, ECA, FANG, HES, MRO, NBL, PE, PXD, WPX, XEC

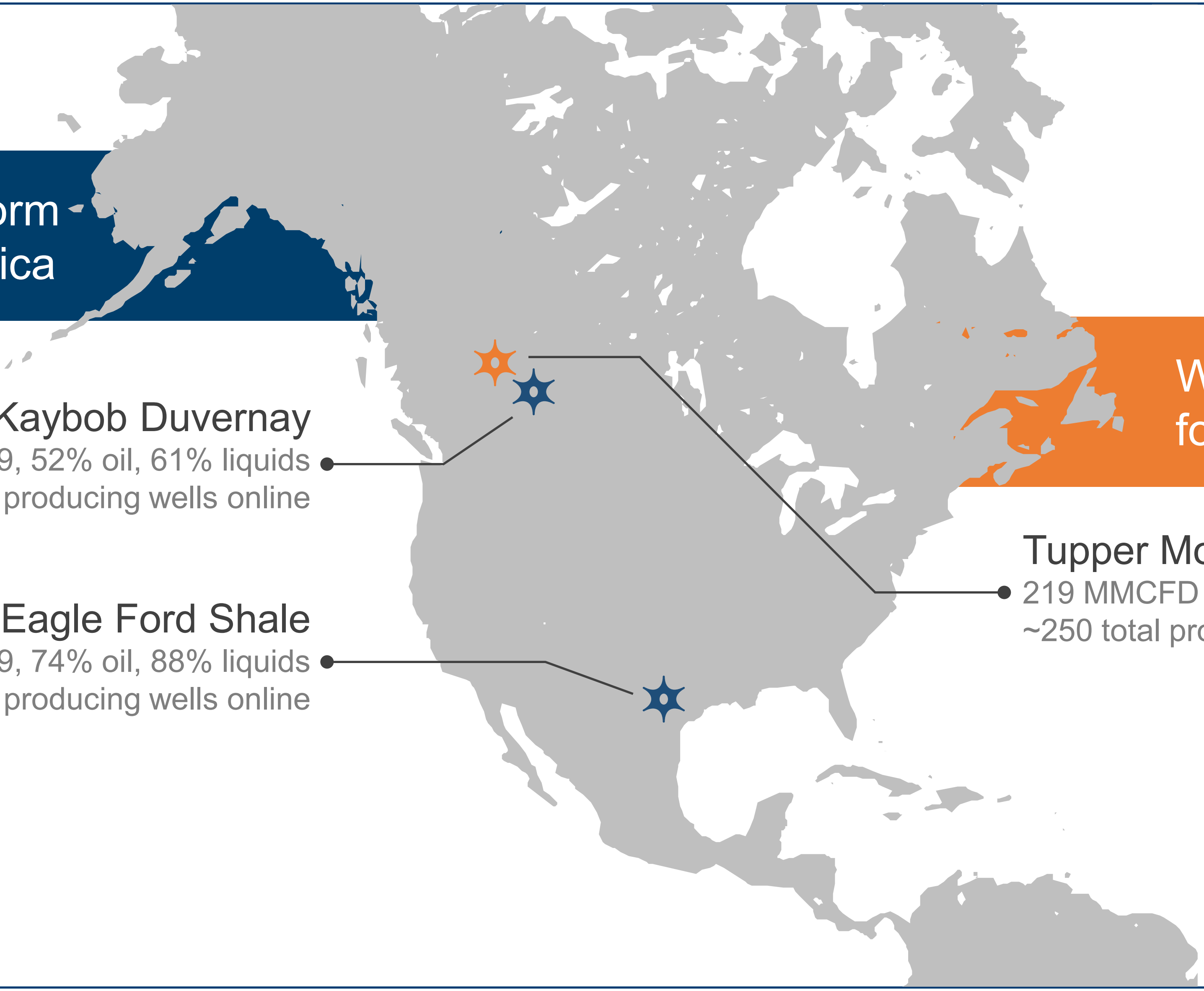
Executing Our 2019 Plan

PRODUCING Oil-Weighted Assets	GENERATING High Margin Realizations	INCREASING Financial Strength	TRANSFORMING with Accretive Acquisitions	BUILDING Profitable Production
159 MBOEPD, >60% Oil in 2Q 2019 >23% increase in Eagle Ford Shale from 1Q Lowered LOE/BOE to <$9 in 1H 2019	94% oil volumes sold at premium to WTI >$26 EBITDA/BOE 2Q 2019 >$38 EBITDA/BOE US & Canada offshore 2Q 2019 Additional oil hedges at average prices >$57 WTI	Returned >$380 MM to shareholders Delivered >4% dividend yield Zero balance on credit facility	Closed Gulf of Mexico & Malaysia transactions Increased reserves liquids-weighting by 5% Established as a top 5 operator in Gulf of Mexico	Sanctioned 3 Gulf of Mexico projects set to deliver sustainable FCF Drilled successful well at Dalmatian DC4 #2

Note: 2Q EBITDA/BOE based on continuing operations

Onshore Portfolio Update

Concentrated Onshore Assets with Repeatable Results



Oil-Weighted Platform Across North America

Kaybob Duvernay
9,300 BOEPD at 2Q 2019, 52% oil, 61% liquids
~80 total producing wells online

Eagle Ford Shale
44 MBOEPD at 2Q 2019, 74% oil, 88% liquids
~980 total producing wells online

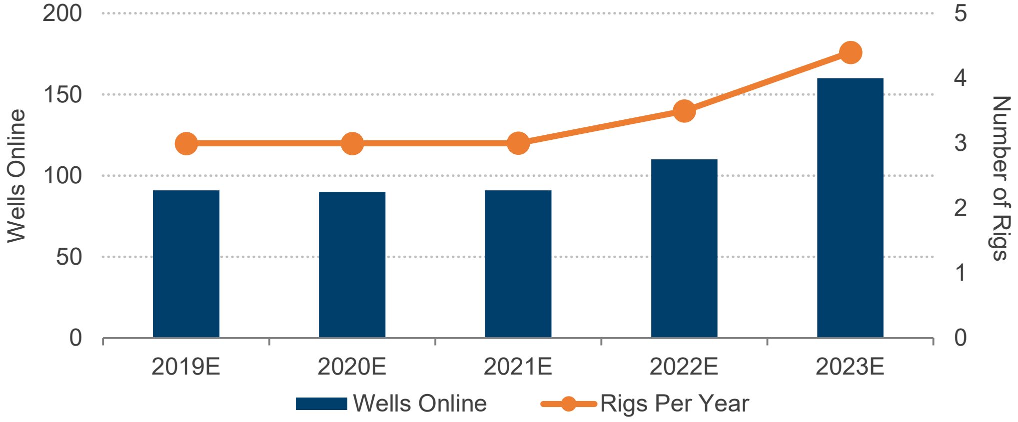
Well-Positioned for Natural Gas

Tupper Montney
219 MMCFD at 2Q 2019
~250 total producing wells online

Significant Running Room in the Eagle Ford Shale

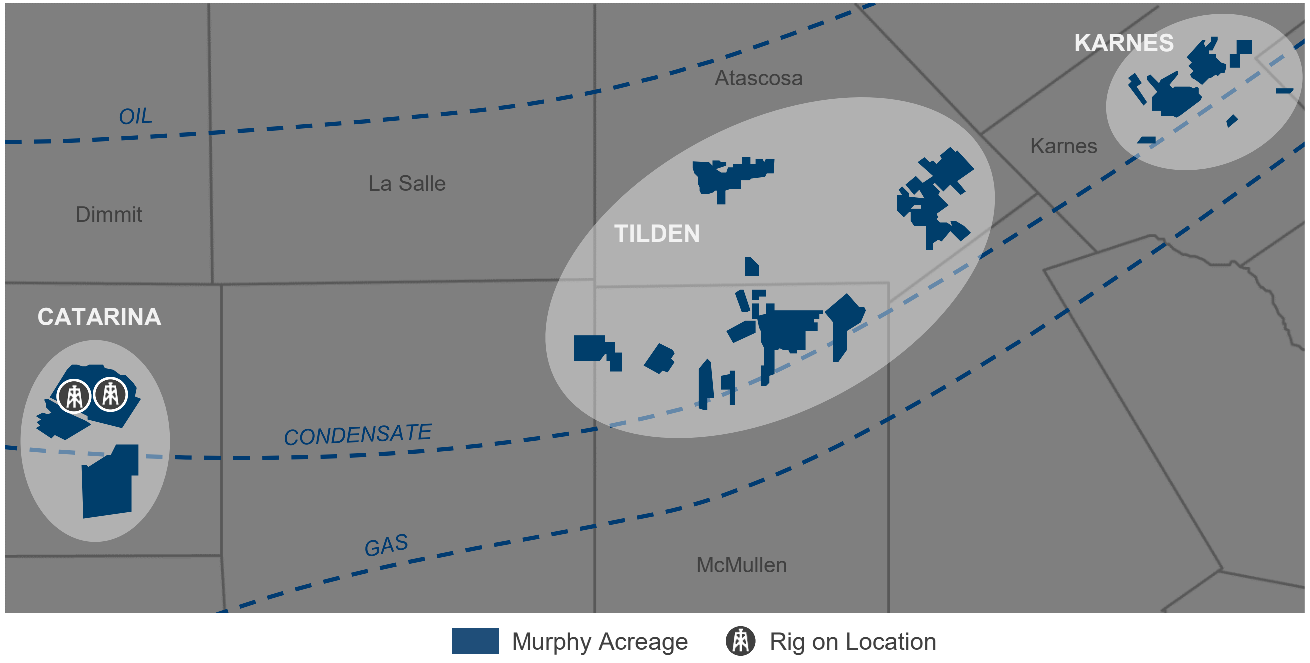
Significant Development Across ~125,000 Net Acres

- 500+ MMBOE total resource potential
- Conservative inter-well spacing, type curves account for parent/child relationship
- Completion designs optimized by pad & well
- Long life asset at low end of cost curve
- Remote operating center with big data focus



** As of December 31, 2018*

Eagle Ford Shale Acreage



Area	Net Acres	Reservoir	Inter-Well Spacing *(ft)*	Remaining Wells*
Karnes	10,918	Lower EFS	300	121
		Upper EFS	700	159
		Austin Chalk	700	108
Tilden	64,737	Lower EFS	500	388
		Upper EFS	500	140
		Austin Chalk	600	100
Catarina	47,653	Lower EFS	450	292
		Upper EFS	600	354
		Austin Chalk	800	149
Total	**123,308**			**1,811**

Eagle Ford Shale

Well Delivery 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

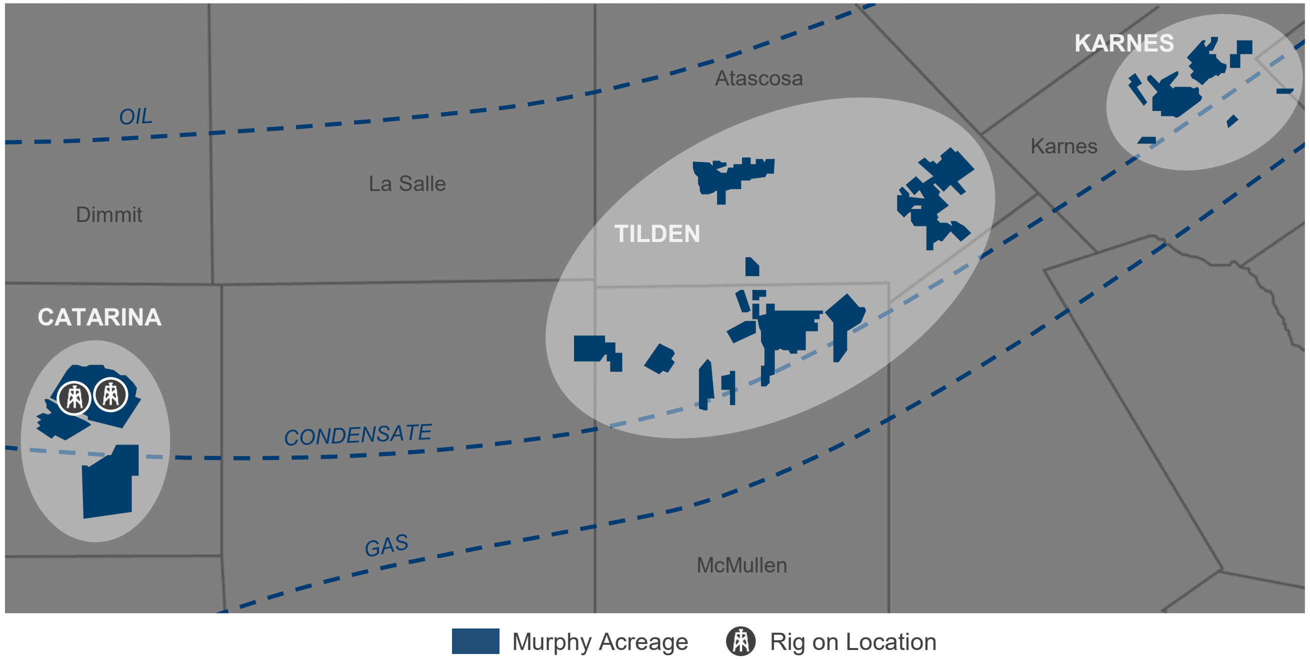
- 25 wells online
  - 10 Tilden – Lower EFS
  - 15 Catarina – 11 Lower EFS, 6 Upper EFS

4Q 2019

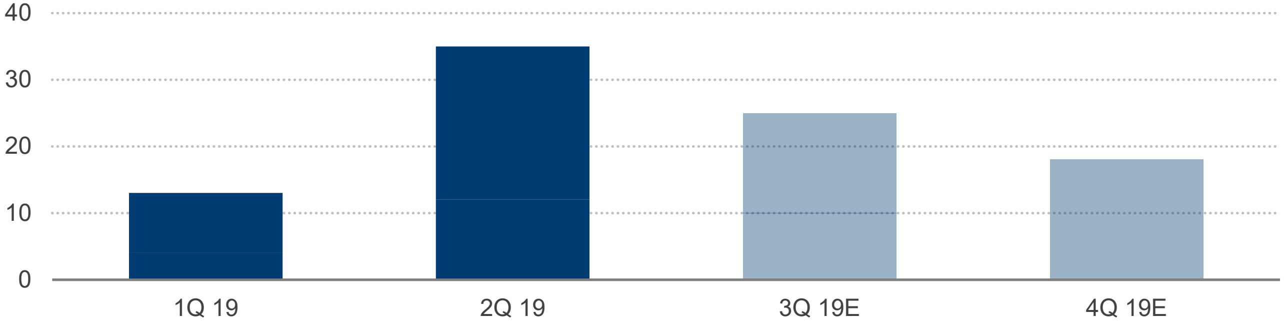
- 18 wells online
  - 8 Tilden – Lower EFS
  - 10 Catarina – Lower EFS

NOTE: EFS = Eagle Ford Shale

Eagle Ford Shale Acreage



Operated Wells Online *2019*

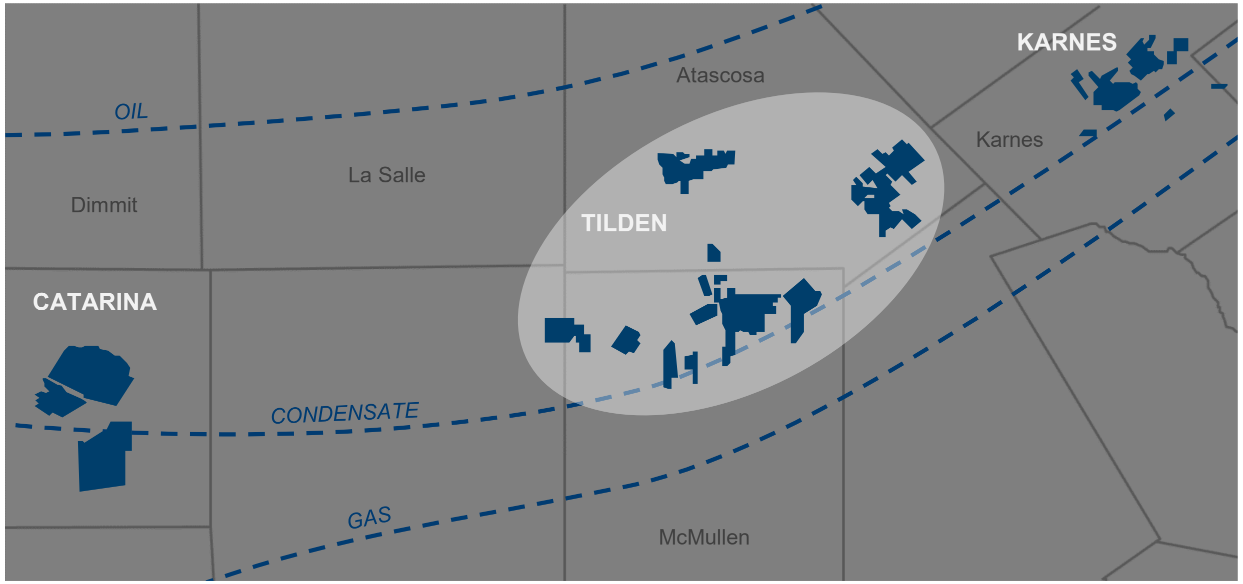


Increasing Returns From New Wells
- Improved well targeting
- Optimized completion design
- Applicable to >350 more locations

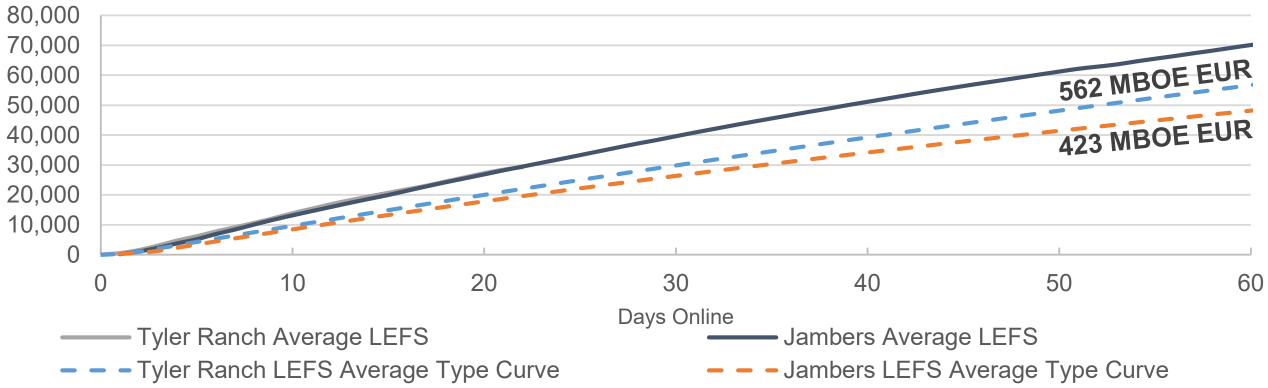
Jambers Pad
- 8 Lower EFS wells online 2Q 2019
  - 6 wells with 9,100’ lateral (IP30 1,440 BOEPD)
  - 2 wells with 4,700’ lateral (IP30 1,200 BOEPD)
  - 500’ well spacing
- Average 24 hour IP ~1,800 BOEPD

Tyler Ranch Pad
- 10 Lower EFS wells online 3Q 2019
  - 10 wells with 7,100’ lateral
  - 500’ well spacing
- Average 24 hour IP ~1,800 BOEPD

Eagle Ford Shale Acreage



Tilden New Well Performance *Cum BOE*



Kaybob Duvernay

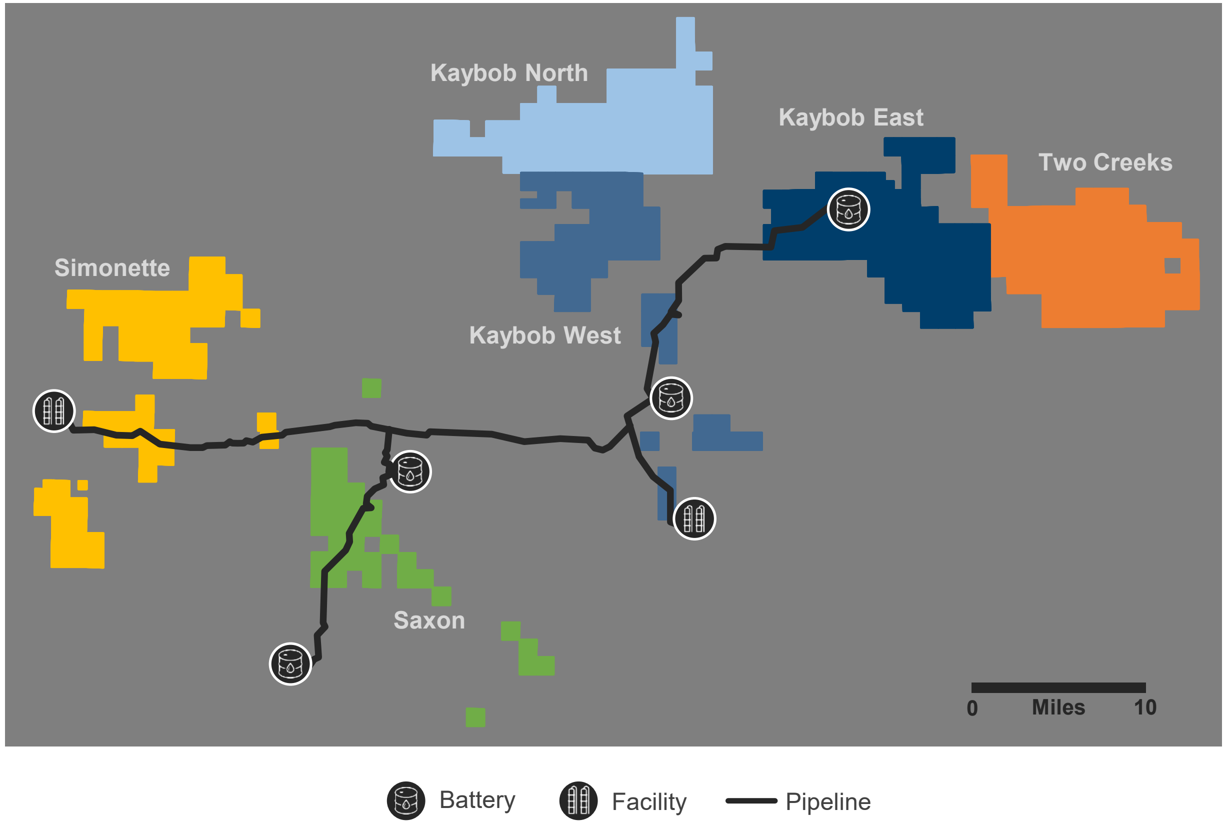
Scalable Assets For Future Growth

Oil-Weighted Production from Low Cost Assets

- Approaching completion of retention drilling
- Optimizing development plan and lateral lengths
- Continuing outperformance with high rate wells
- Targeting $6.5 MM per well drilling and completions costs

Area	Net Acres	Inter-Well Spacing *(ft)*	Remaining Wells
Two Creeks	34,336	984	123
Kaybob East	36,400	984	182
Kaybob West	25,760	984	119
Kaybob North	31,360	984	129
Simonette	29,715	984	82
Saxon	12,746	984	37
Total	**170,317**		**672**

Kaybob Duvernay Acreage



Kaybob Duvernay

Well Delivery Update

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 cashless acreage swap
  - Acquired 20,000 gross acres in Kaybob East / Two Creeks in exchange for 5,800 gross acres
  - Optimized development plan & lateral lengths
- 3 Simonette wells resumed production in 3Q 2019

2H 2019 Land Retention Plan

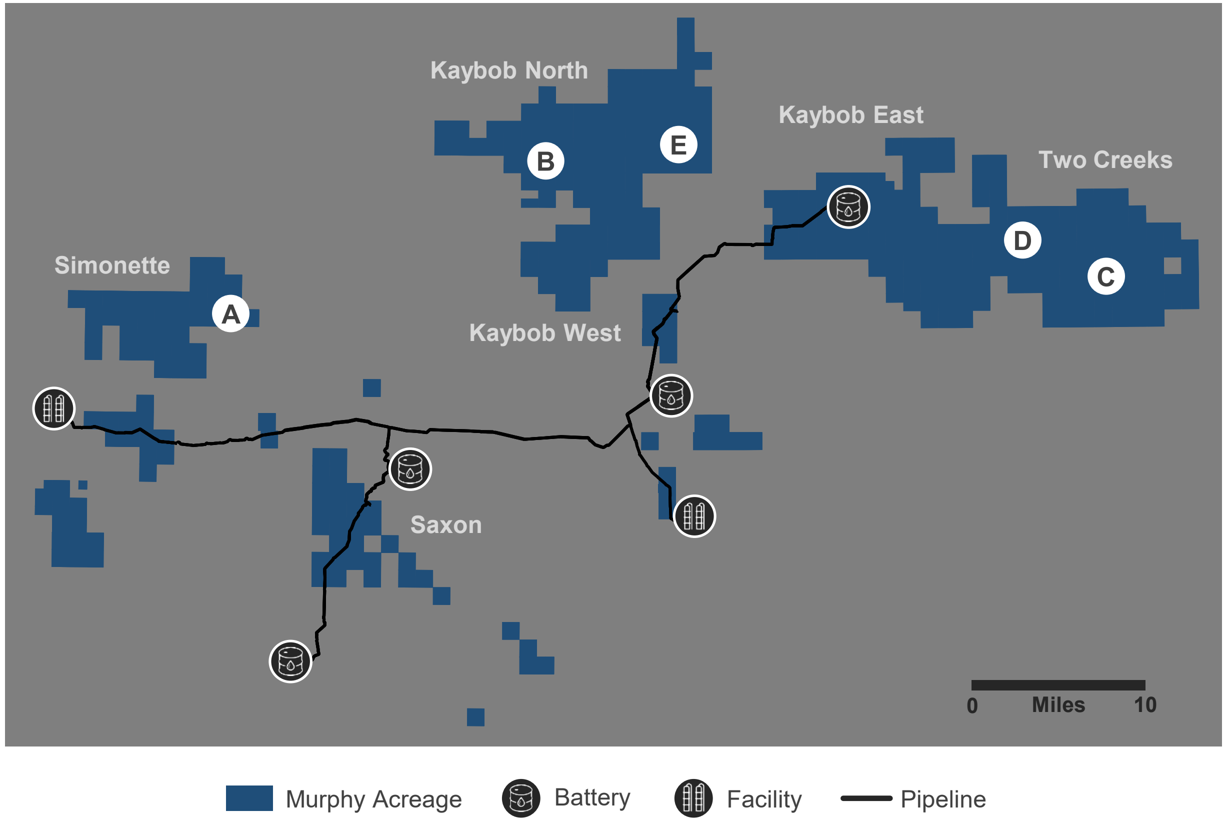
- Drill 13 wells
- Scheduled to come online in 2020

2019 Online Wells

Area	Pad	Wells Online	IP30 (BOEPD)	Liquids
A	08-03	3	1,400*	86%
B	05-23	2	1,054	86%
C	05-19	2	651*	91%
D	16-29	2	858*	91%
E	16.25	1	834*	85%

** Well volumes constrained due to current facility limitations.*

Kaybob Duvernay Acreage



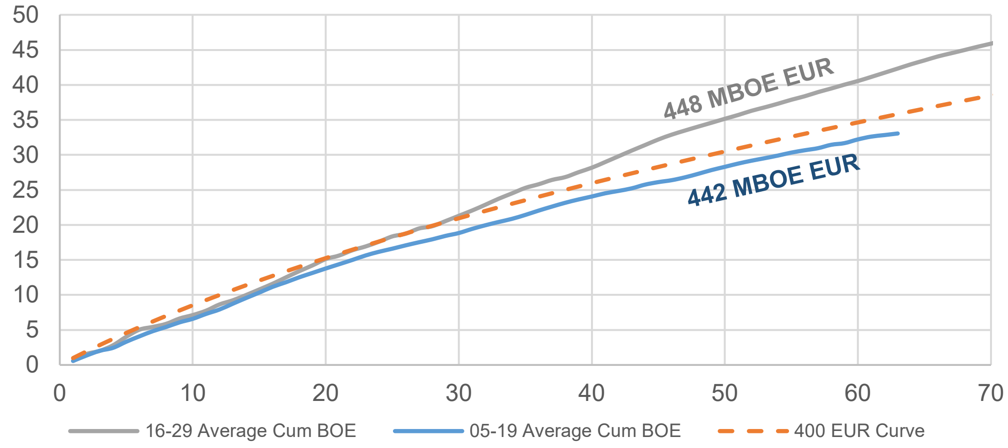
Kaybob Duvernay
New Two Creeks Wells Exceeding Expectations

Results From De-Risking Improve Returns
- Increased oil content from appraisal wells
- Improved completion design

16-29 Pad
- Two wells on pad – initial rate restricted
- Average IP30 rate of ~860 BOEPD (91% liquids)

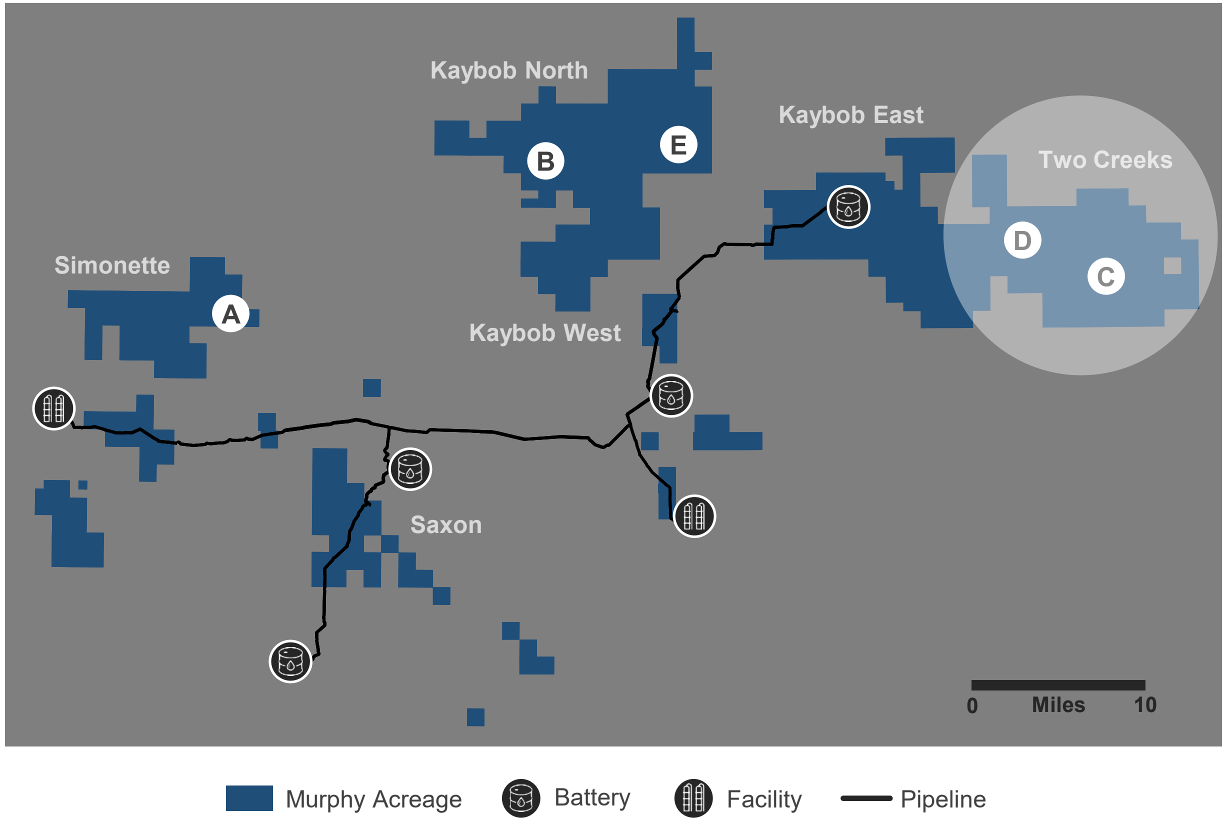
05-19 Pad
- Two wells on pad – initial rate restricted
- Average IP30 rate of ~650 BOEPD (93% liquids)

Two Creeks New Well Performance *Cum MBOE*



Note: Initial rates restricted due to facility limitations

Kaybob Duvernay Acreage



Canada Onshore
Tupper Montney Update

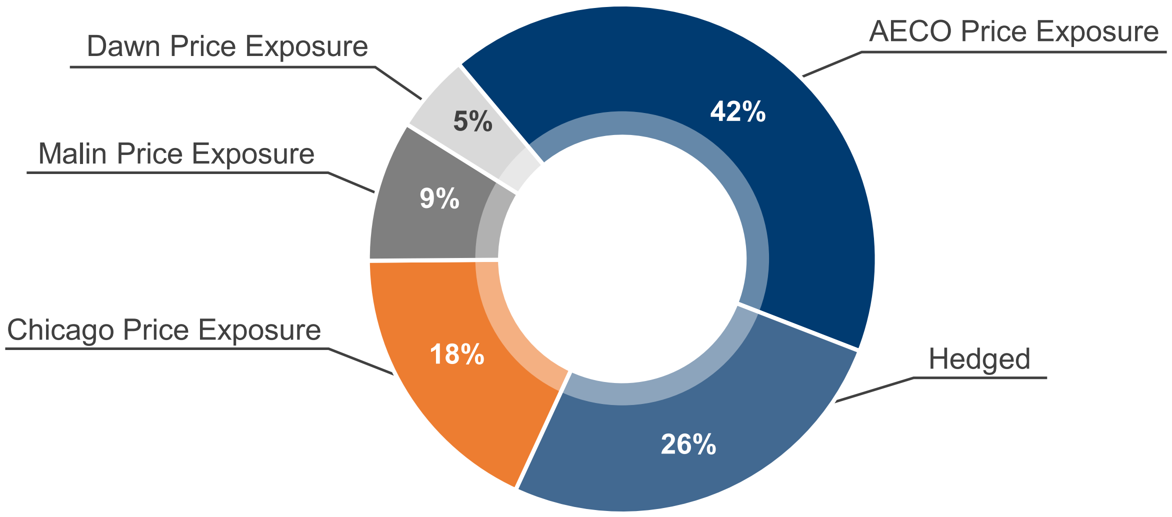
2019 Well Delivery Plan Complete
- 8 wells online

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

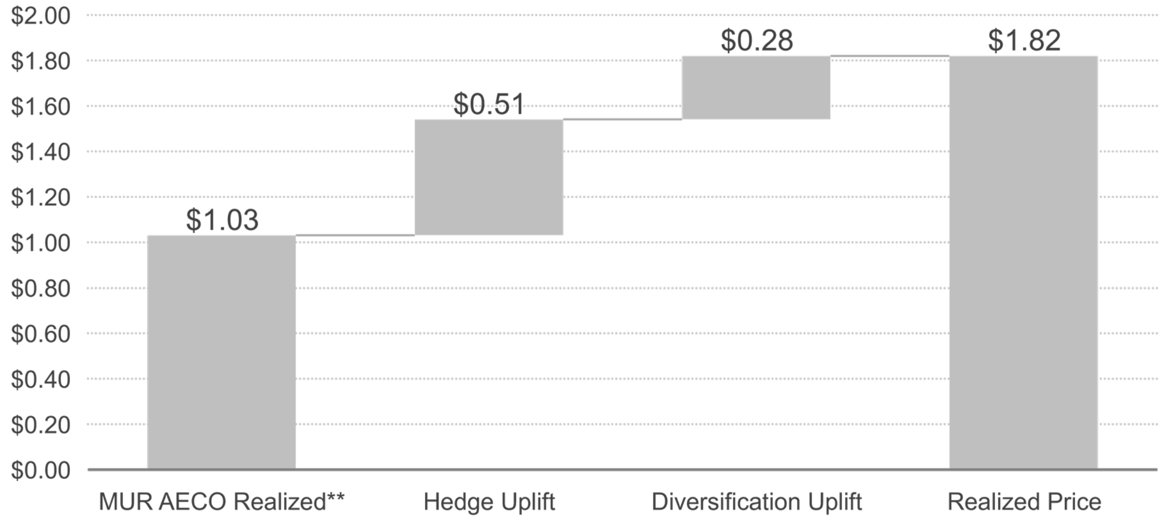
Successful AECO Price Mitigation
- Realized 2Q 2019 C$1.82/MCF* vs AECO realized average of C$1.03/MCF
- Projected FY 2019 C$2.27/MCF* vs AECO realized average of C$1.69/MCF

** C$0.28 Transportation Cost to AECO Not Subtracted*

Mitigating AECO Exposure
2Q 2019 Tupper Montney Natural Gas Sales



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



** C$0.28 of Transportation Cost Not Subtracted*

Offshore Portfolio Update

MURPHY
OIL CORPORATION

Gulf of Mexico

Free Cash Flow Generating Assets

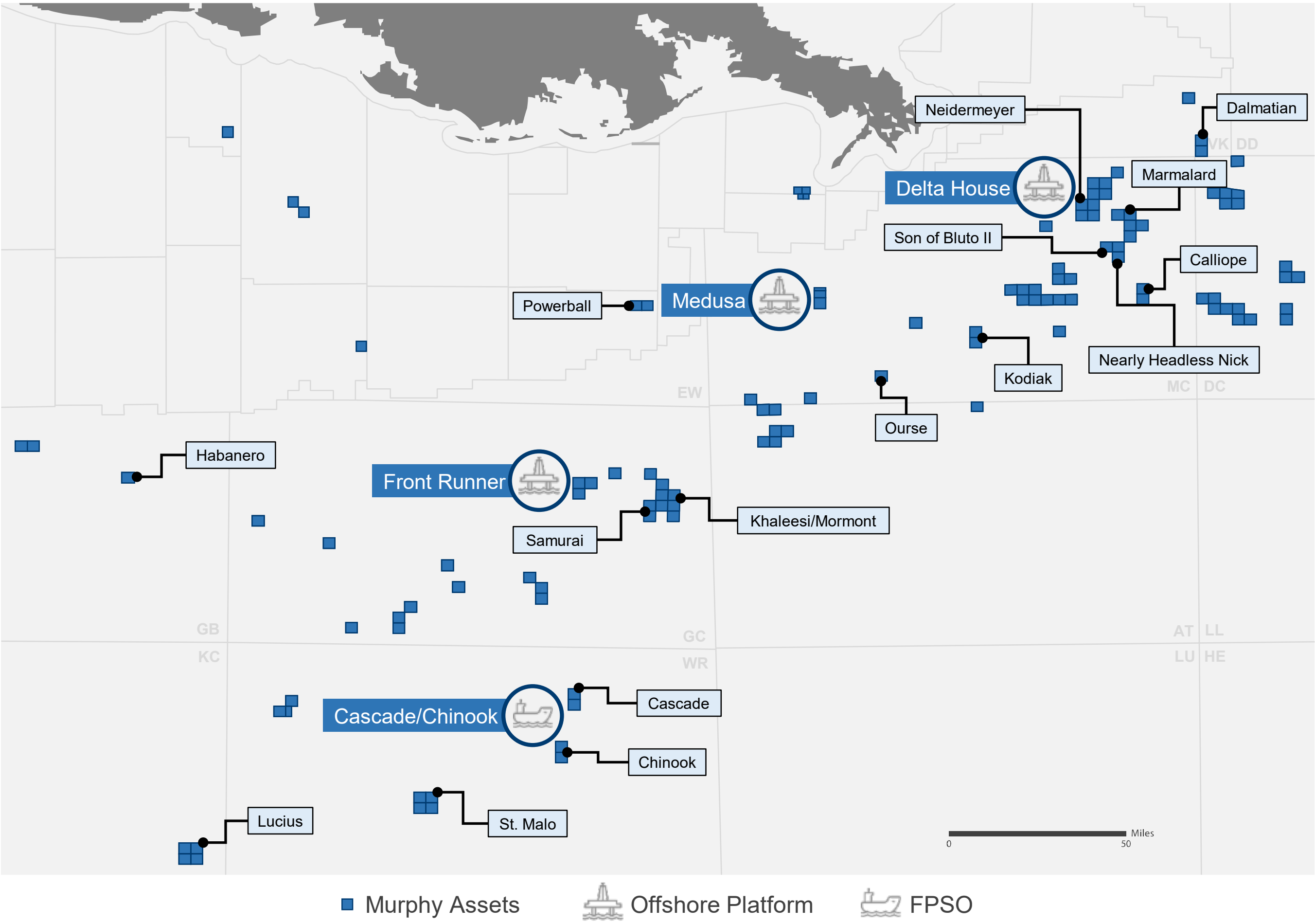
Revitalized Portfolio

- Top 5 Gulf of Mexico operator by production
- Achieves high margin EBITDA/BOE
- Generating ongoing synergies from acquisitions
- Long runway for further development projects

PRODUCING ASSETS		
Asset	Operator	Murphy WI[1]
Cascade	Murphy	80%
Chinook	Murphy	53%
Clipper	Murphy	80%
Cottonwood	Murphy	80%
Dalmatian	Murphy	56%
Front Runner	Murphy	50%
Habanero	Shell	27%
Kodiak	Kosmos	48%
Lucius	Anadarko	9%
Marmalard	Murphy	27%
Marmalard East	Murphy	70%
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 Non-Controlling Interest

Gulf of Mexico Assets



Gulf of Mexico
2Q 2019 Operations Update

2019E Production 85 MBOEPD, 90% Liquids

- Closed Gulf of Mexico acquisition 2Q 2019
- Exceeded 2Q 2019 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
- Estimated gross incremental rate ~6,000 BOEPD
- Payback period < 18 months
- IRR > 90%

Hoffe Park #2 Well

- Oil discovered in multiple zones

Front Runner SPAR

2019E production assumes full year impact of acquired assets in LLOG transaction

Gulf of Mexico

Short Cycle Capital Projects Deliver Accelerated Returns

Gulf of Mexico Short Cycle Projects

New Wells	Completions & Tie-Backs	Workovers
Dalmatian DC4 #2	Nearly Headless Nick	Cottonwood
Son of Bluto II	Ourse	
	Calliope	

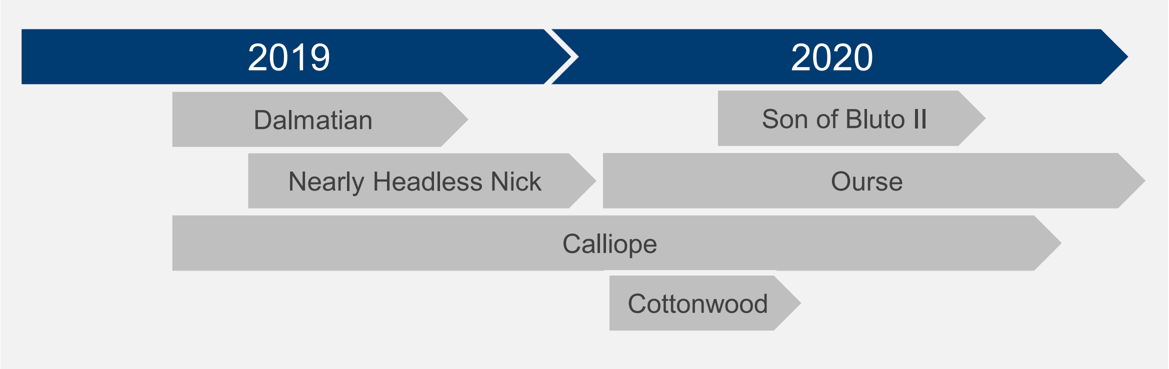
21 **MMBOE** Total Net Resources

$7.50 **/BBL** CAPEX

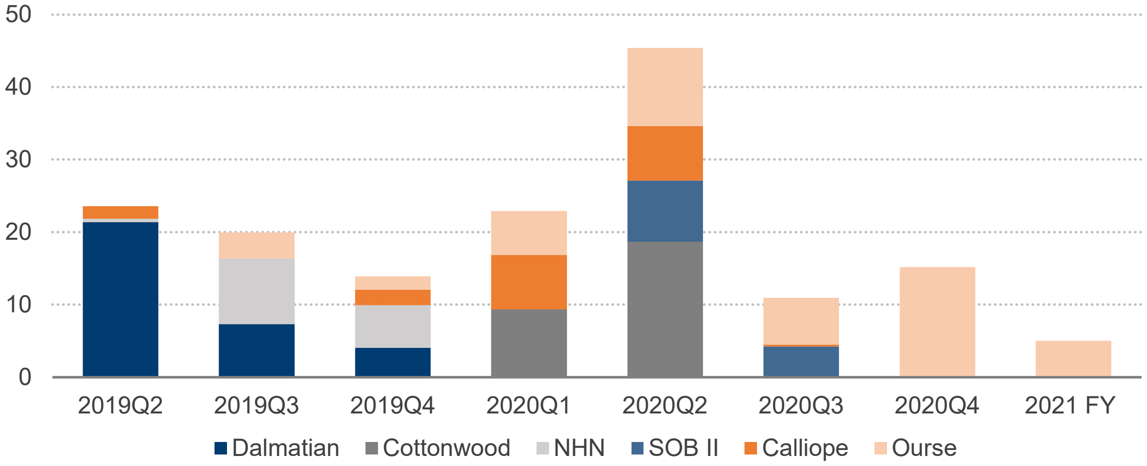
>80 **% IRR** Average Project

WTI $55/BBL, 2019-2023

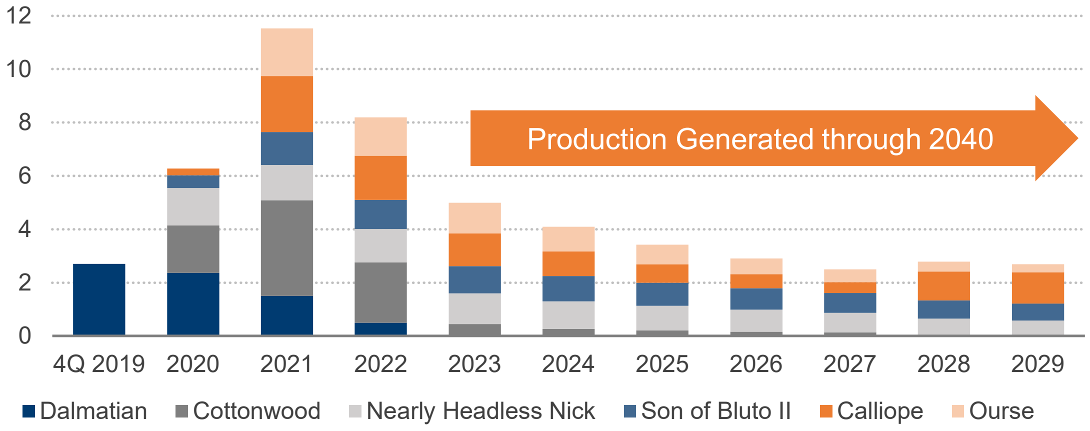
Development Timeline



Net CAPEX *$MM*



Net Production *MBOEPD*



Production volumes may vary based on timing and performance
Production volumes, reserves and financial amounts exclude non-controlling interest

Gulf of Mexico

Investing in Long Term High-Margin Projects

Khaleesi/Mormont

- Gross resource ~165 MMBOE, 90% liquids
- 7 development wells planned – 4 previously drilled
- IRR > 30%, NPV > $300 MM

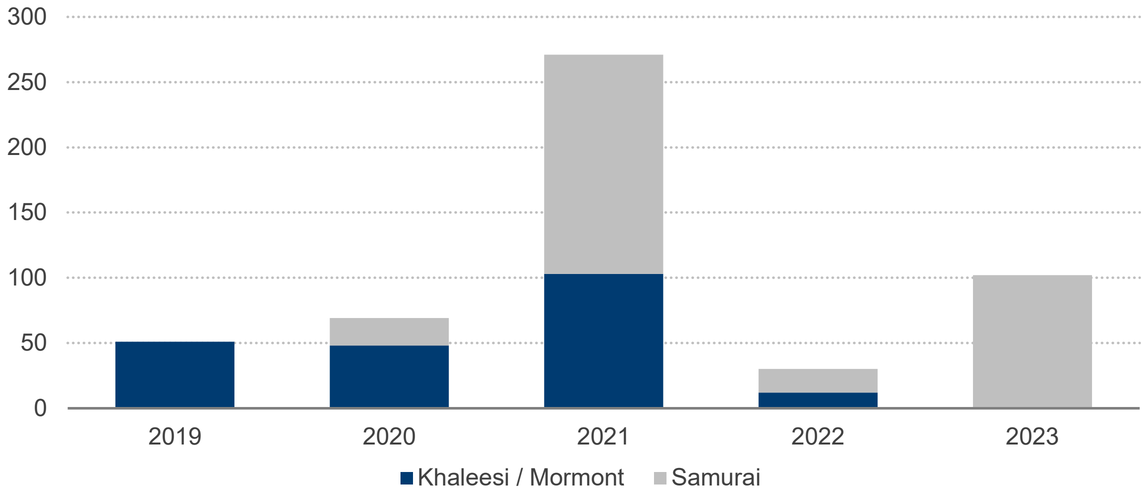
Samurai

- Gross resource ~60 MMBOE, 90% liquids
    - Potential upside ~15 MMBOE
- 4 development wells planned
- IRR > 35%, NPV > $200 MM

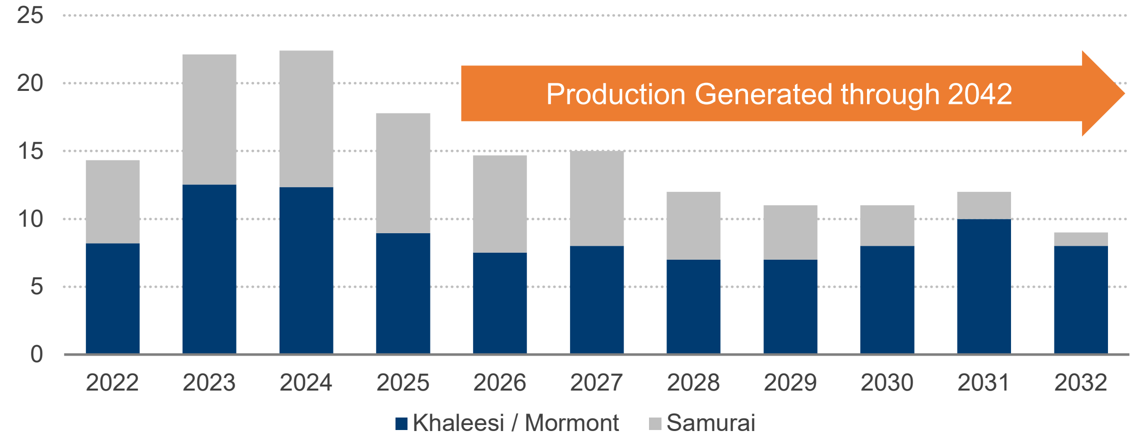
WTI $55/BBL, 2019-2023

Development Timeline

Net CAPEX *$MM*



Net Production *MBOEPD*



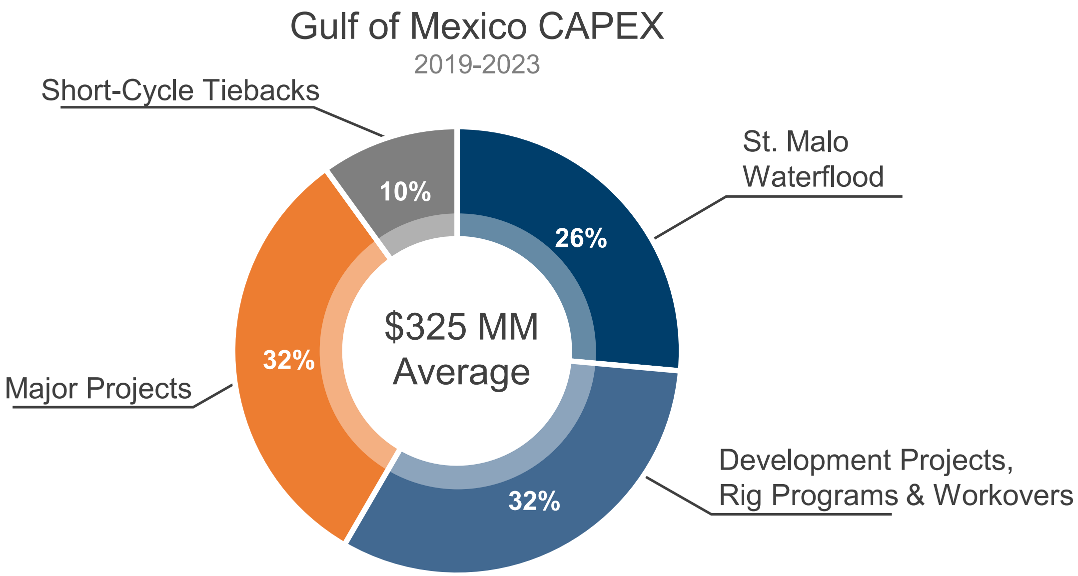
Production volumes may vary based on timing and performance
Production volumes, reserves and financial amounts exclude non-controlling interest

Gulf of Mexico

Generating Long Term Free Cash Flow

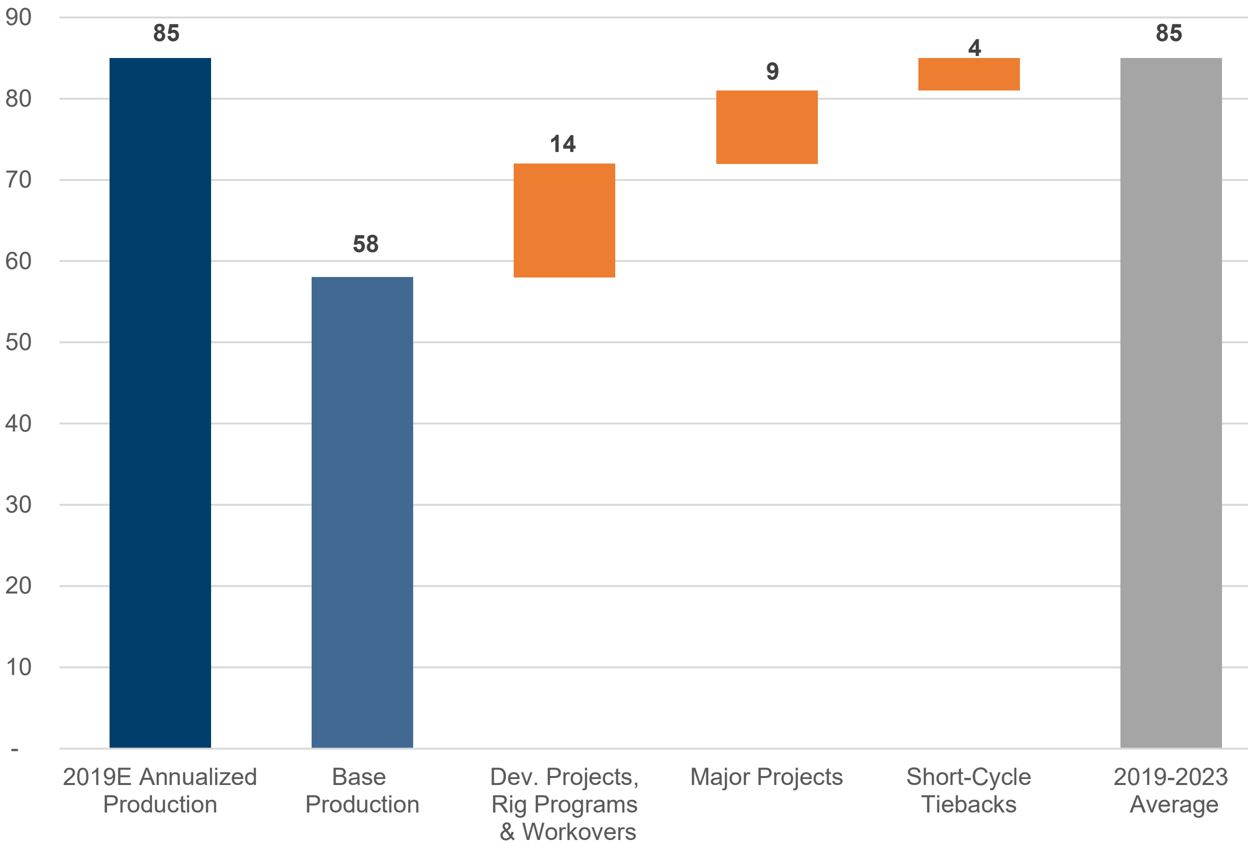
Capital Commitments Support Long Term Growth

- Sanctioning St. Malo waterflood project 3Q 2019
- Maintaining $325 MM average CAPEX 2019 – 2023 assuming King's Quay sell down
- Affirming 2019 CAPEX guidance
- Producing 85 MBOEPD average from 2019 – 2023
- Delivering sustainable cash flow from large inventory of development projects



CAPEX from Major Projects include Samurai and Khaleesi / Mormont
St. Malo Waterflood CAPEX includes $50 MM carry for Petrobras Americas Inc.
Production volumes, sales volumes, reserves and financial amounts exclude non-controlling interest, unless otherwise stated

2019 – 2023 Estimated Gulf of Mexico Production *MBOEPD*



2019E Annualized Production assumes full year impact of acquired assets in LLOG transaction
Production from Major Projects includes St Malo Waterflood, Samurai and Khaleesi / Mormont

Exploration Update

MURPHY
OIL CORPORATION

Exploration Strategy Overview

Focused & Meaningful

- Four primary exploration areas
- 3 to 5 exploration wells per year
- ~$100 MM/year

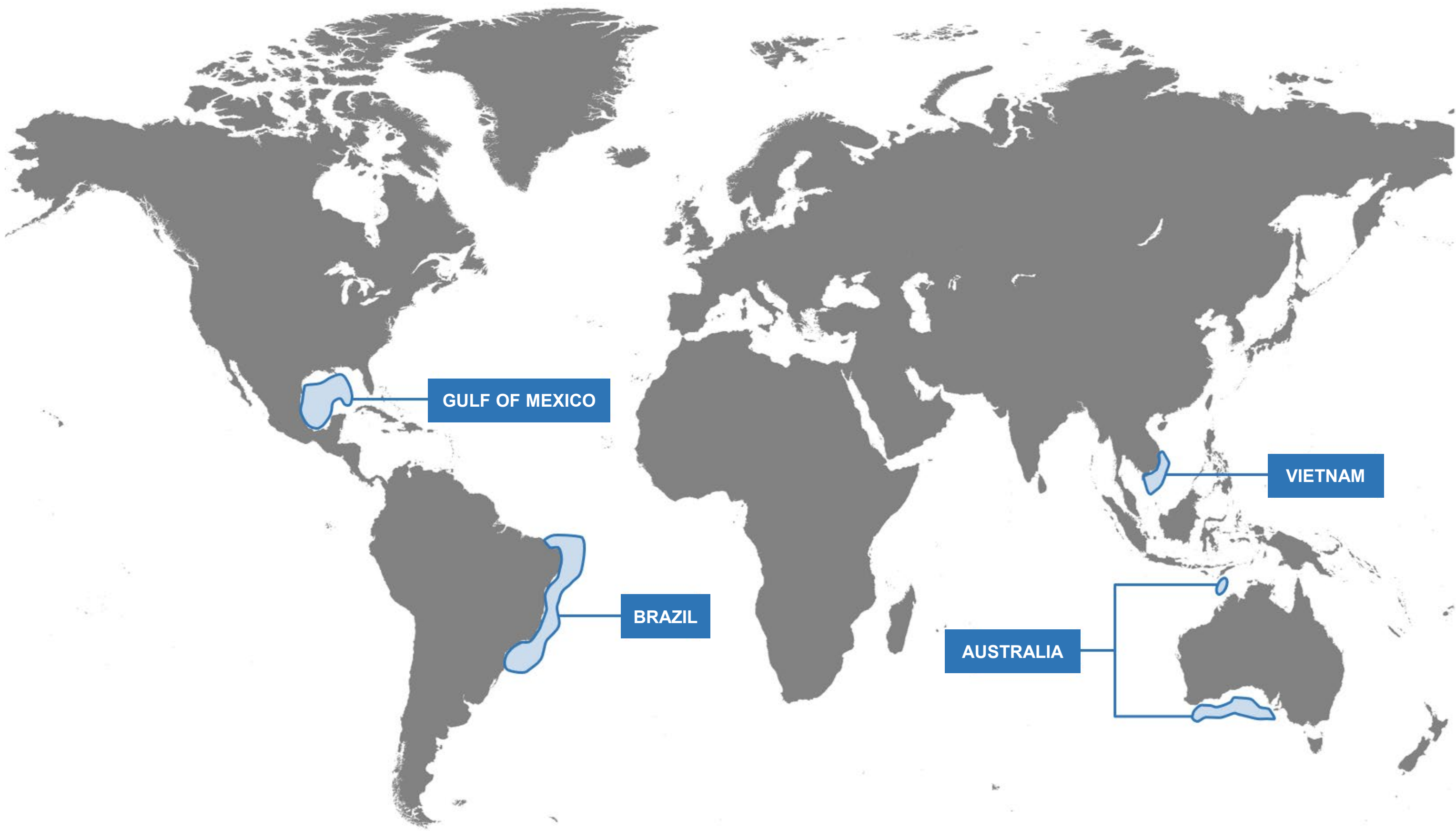
Reduced Risk

- Proven oil provinces
- Targeting appropriate working interest
- Leveraging strategic partnerships

Strategic Themes

- Consistent US Gulf of Mexico program
- Field extension and exploration in Vietnam
- Company-making potential from Brazil and Mexico
- Targeting < $12/BBL full-cycle finding and development cost

Exploration Core Focus Areas



Brazil Exploration Update

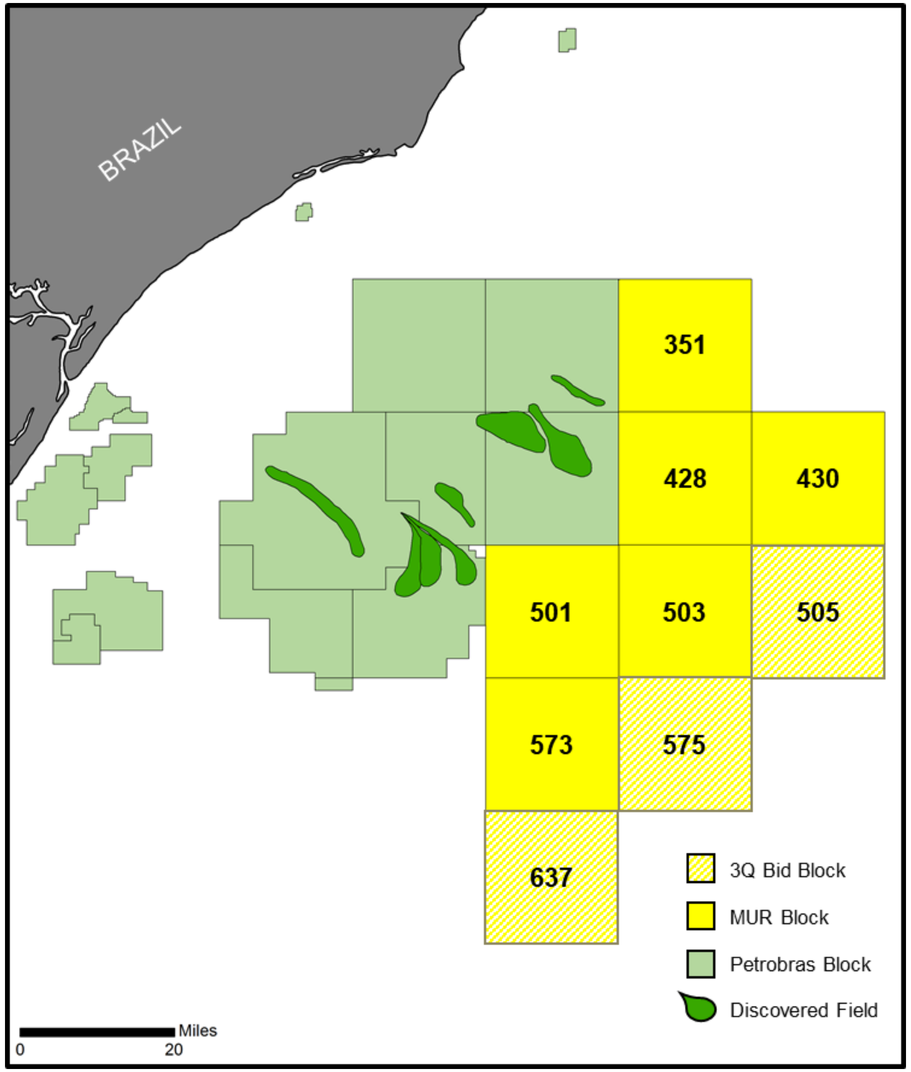
Sergipe-Alagoas Basin Overview

- Murphy 20% (Non-Op), ExxonMobil 50% (Op), Enauta Energia S/A 30%
- > 1.2 BN BOE reserves discovered inboard
- Working interests in 6 blocks, ~1,100 M acres
- Winning bid on 3 adjacent blocks, ~560 M acres
  - 3Q 2019 Blocks 505, 575 and 637

Continuing to Evaluate Data

- Progressing seismic program and interpretation
- Providing long-term exploration upside

Sergipe-Alagoas Basin



Offshore Mexico Discovery at Cholula

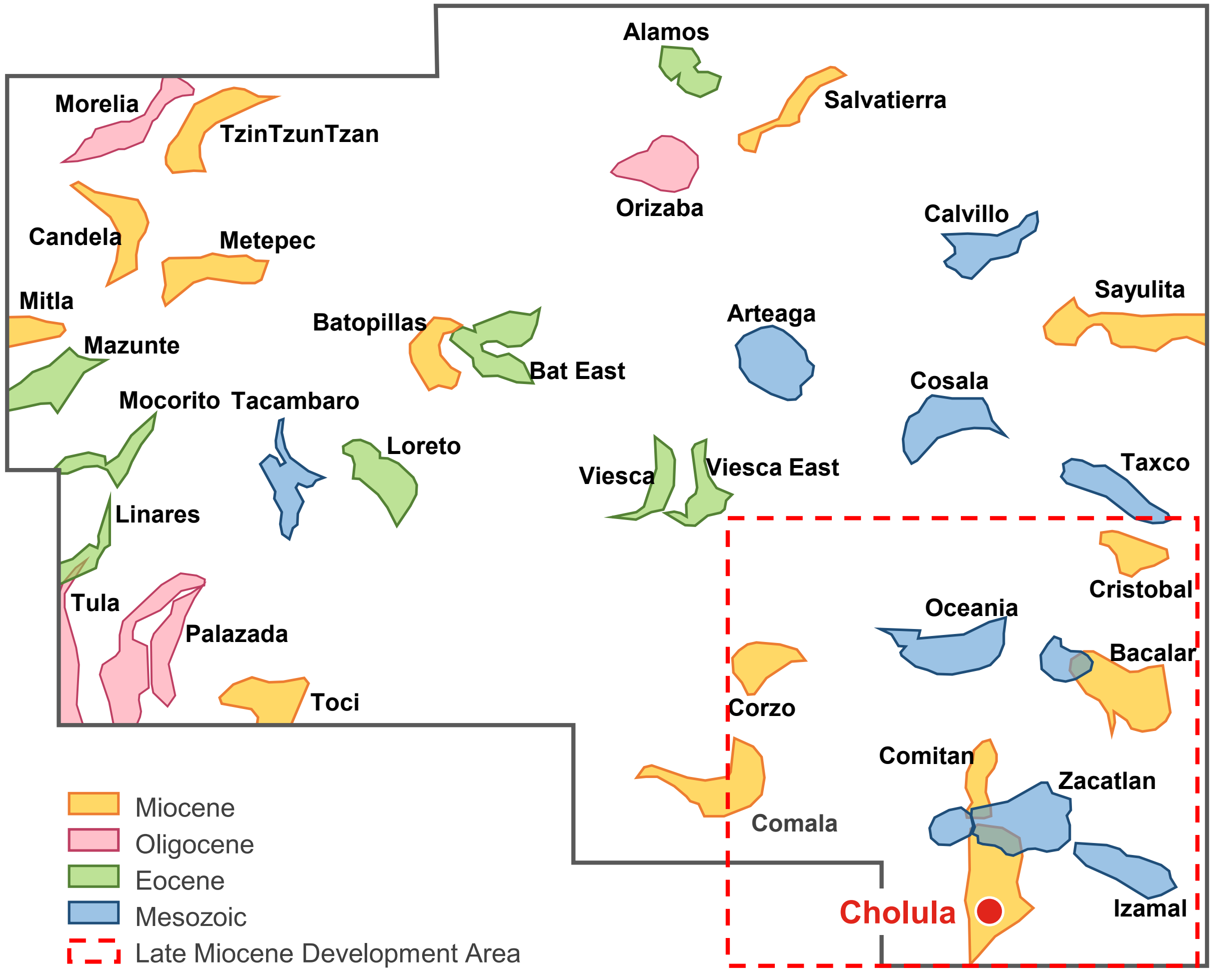
Block 5 Overview

- Murphy 40% (Op), Petronas 30%, Wintershall DEA 30%
- 34 leads / prospects
- Mean to upward gross resource potential:
  - 800 MMBO – 2,000 MMBO
- Planning additional exploration program in 2020

Cholula 1-EXP Highlights

- ~$12 MM net drilling costs
- Drilled to total depth (TD) of 8,825 feet
- Discovered 185 feet net hydrocarbon pay
  - Validates block potential
  - De-risks Upper Miocene play in SE corner of Block 5
- ~200 MMBOE of resources within tie-back distance

Block 5 Prospects



Vietnam Cuu Long Basin Update

Cuu Long Basin Overview

- Murphy 40% (Op), PVEP 35%, SKI 25%
- > 400 MMBOE remaining resource potential on Block 15-1/05

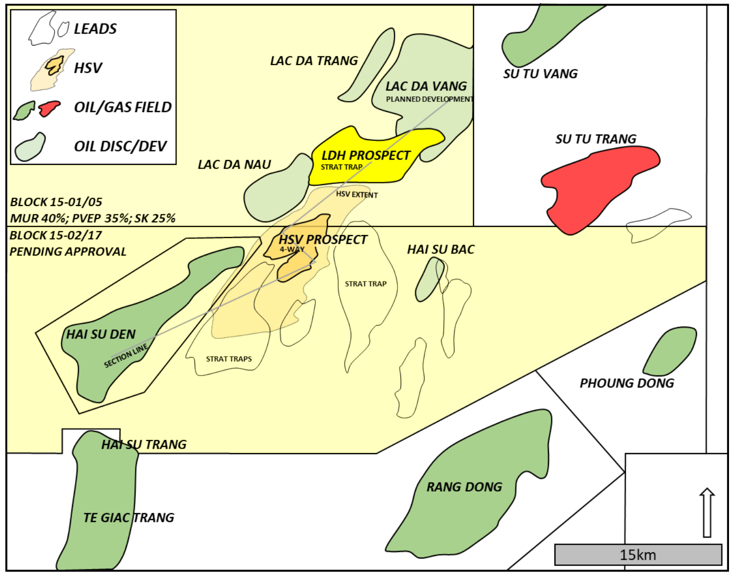
Block 15-2/17 PSC

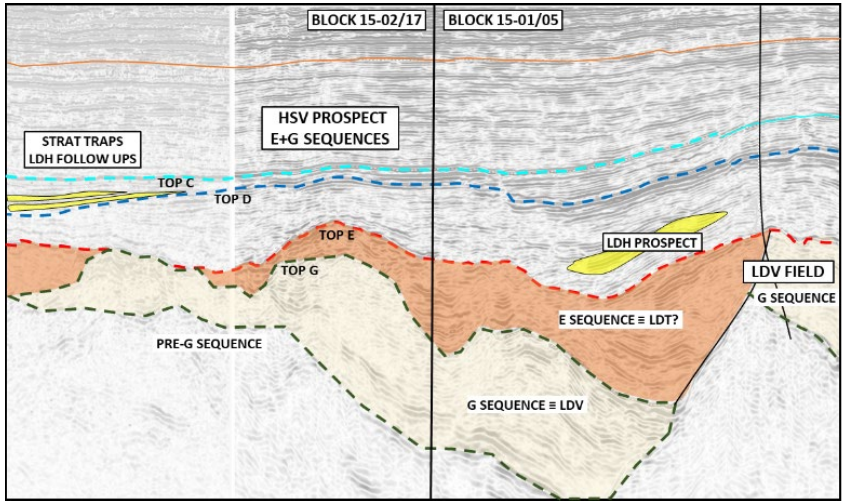
- Resource potential adds value to core area
  - Adjacent to LDV field under development

LDT-1X Exploration Well

- Estimated Discovered Resources ~39 MMBO
  - Additional Resource Potential in “D” Sequence Pay

Cuu Long Basin





Looking Ahead

MURPHY
OIL CORPORATION

Executing Our Strategy in 2019

Transforming the Company for Long-Term Success

- Strengthening balance sheet by lowering debt
- Increasing oil-weighted production through several major transactions
- Shifting production to tax-advantaged region
- Achieving premium Gulf of Mexico oil-weighted realizations
- Continuing to deliver steady production growth in the Eagle Ford Shale
- Executing Gulf of Mexico field development projects

$300 Million
Share Re-Purchase Completed by YE 2019

200 MBOEPD
Production Rate by 4Q 2019

68 %
Liquids-Weighted Production in 2H 2019

>95 %
Sales Volumes at Premium to WTI in 2H 2019

>50 Wells Online
in Eagle Ford Shale in 2H 2019

Executing on Long-Term Plan

Maintaining > 65% Liquids Production Weighting

- Plan flexible to maintain cash flow / CAPEX parity including dividend

US Onshore – Focusing on Oil-Weighted Growth

Canada Onshore – Scalable Based on Market Conditions

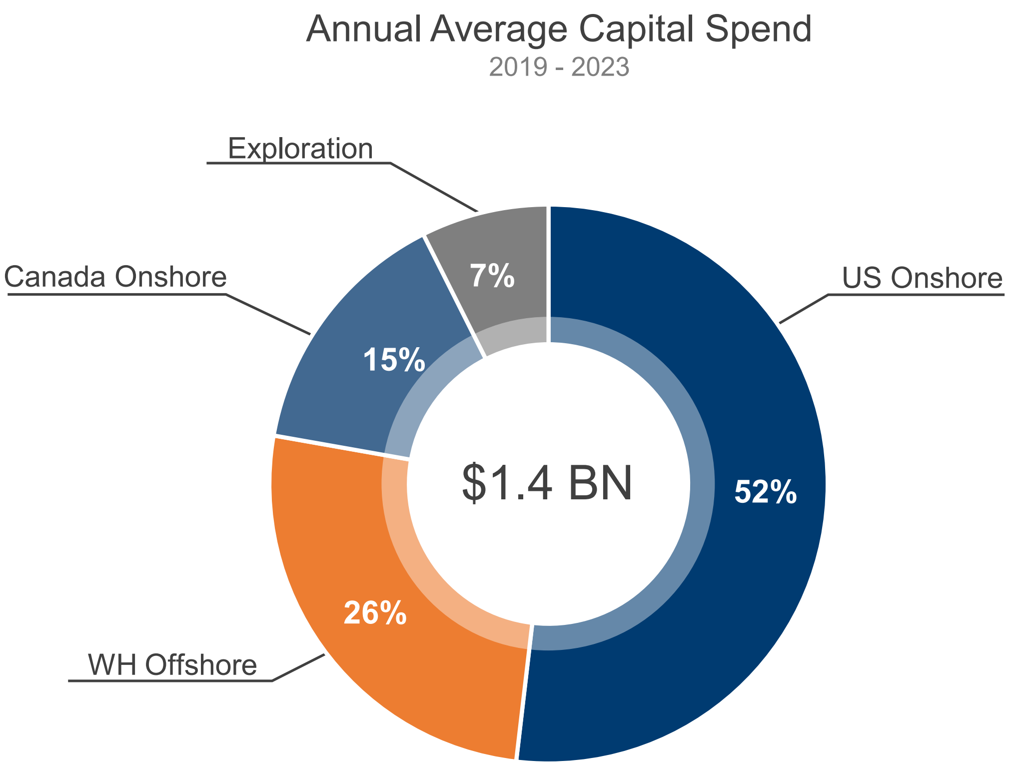
- Focused on lease retention

NA Offshore – Maintaining Current Production

- Consistent free cash flow business
- Short-cycle tiebacks and development projects at existing facilities
- St. Malo waterflood, Khaleesi/Mormont and Samurai projects included

Exploration – Dedicated Strategy

- CAPEX ~$100 MM per year, flexible as needed
- Ongoing plan of 3-5 wells annually



Production volumes, sales volumes, reserves and financial amounts exclude non-controlling interest, unless otherwise stated

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
High value Eagle Ford Shale production

EXECUTING
Short cycle Gulf of Mexico field development projects

OFFERING
Investors exploration upside

FOCUSING
On shareholder priorities

Appendix

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

EBITDA and EBITDAX

Murphy defines EBITDA as income from continuing operations attributable to Murphy[1] 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.

$ Millions	Three Months Ended – June 30, 2019	Three Months Ended – June 30, 2018
Net income (loss) attributable to Murphy (GAAP)	92.3	45.5
Discontinued operations loss (income)	(24.4)	(70.7)
Income tax expense (benefit)	9.1	2.6
Interest expense, net	54.1	44.3
DD&A expense	246.0	190.8
EBITDA attributable to Murphy (Non-GAAP)	**401.5**	**283.2**
Discontinued operations loss (income)	(24.4)	(70.7)
EBITDA attributable to Murphy excluding discontinued operations (Non-GAAP)	**377.1**	**212.5**
Exploration Expense	30.7	18.9
EBITDAX attributable to Murphy excluding discontinued operations (Non-GAAP)	**407.8**	**231.4**

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 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.

$ Millions, except per BOE amounts	Three Months Ended – June 30, 2019	Three Months Ended – June 30, 2018
EBITDA attributable to Murphy excluding discontinued operations (Non-GAAP)	377.1	212.5
Mark-to-market (gain) loss on crude oil derivative contracts	(50.8)	(12.7)
Mark-to-market (gain) loss on contingent consideration	15.4	-
Business development transaction costs	7.8	-
Accretion of asset retirement obligations	9.9	6.4
Foreign exchange losses (gains)	3.0	(12.2)
Adjusted EBITDA attributable to Murphy (Non-GAAP)	**362.4**	**194.0**
Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)	14,268	11,019
Adjusted EBITDA per BOE (Non-GAAP)	**26.43**	**17.61**

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

Non-GAAP Reconciliation

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.

$ Millions	2016	2017	2018	2019E[1]	Total
Net cash provided from continuing operations activities (GAAP)	601	1,128	1,219	1,524	**4,472**
Property additions and dry hole costs	(927)	(1,010)	(1,103)	(1,336)	**(4,375)**
Free cash flow (Non-GAAP)	**(326)**	**118**	**117**	**188**	**97**
Market Cap on December 31	5,361	5,358	4,048	3,779[2]	**18,546**
				Free cash flow yield	**0.5%**

1 2019 estimate data obtained from FactSet estimates on September 17, 2019
2 MUR Market Cap September 17, 2019

Non-GAAP Reconciliation

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.

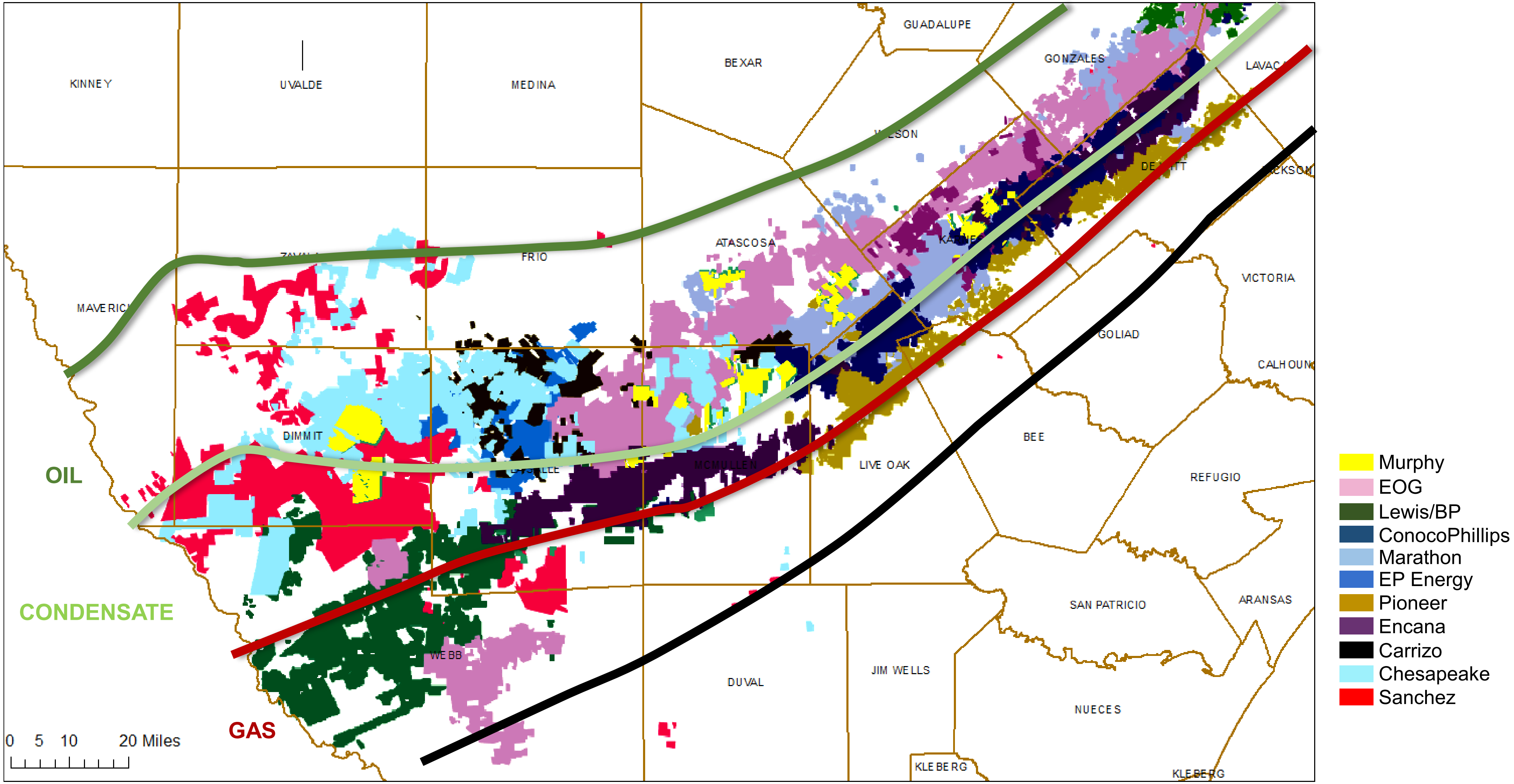
Dividend + Buyback issuance yield annualized is used by management to evaluate the company’s return to shareholders.

$ Millions	2016	2017	2018	2019E	Total
Cash dividends paid (GAAP)	206.6	172.6	173.0	165.3	**718**
Purchase of treasury stock (GAAP)	0.0	0.0	0.0	300.0	**300**
Total Paid to Shareholders	**206.6**	**172.6**	**173.0**	**465.3**	**1,018**
Market Cap on December 31	5,361	5,358	4,048	3,779[1]	**18,546**
				Dividend + Buyback – Issuance Yield Annualized	**5.5%**

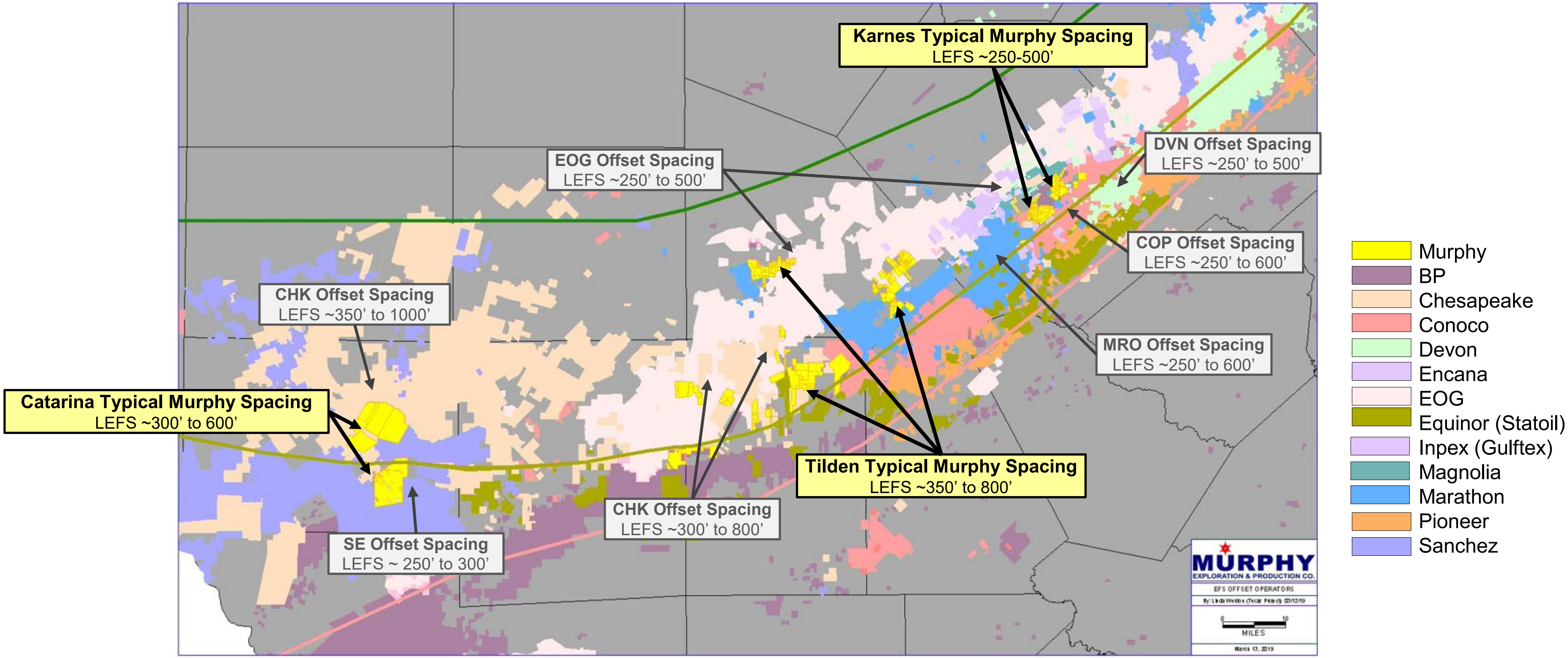
1 MUR Market Cap September 17, 2019

Eagle Ford shale

Peer Acreage

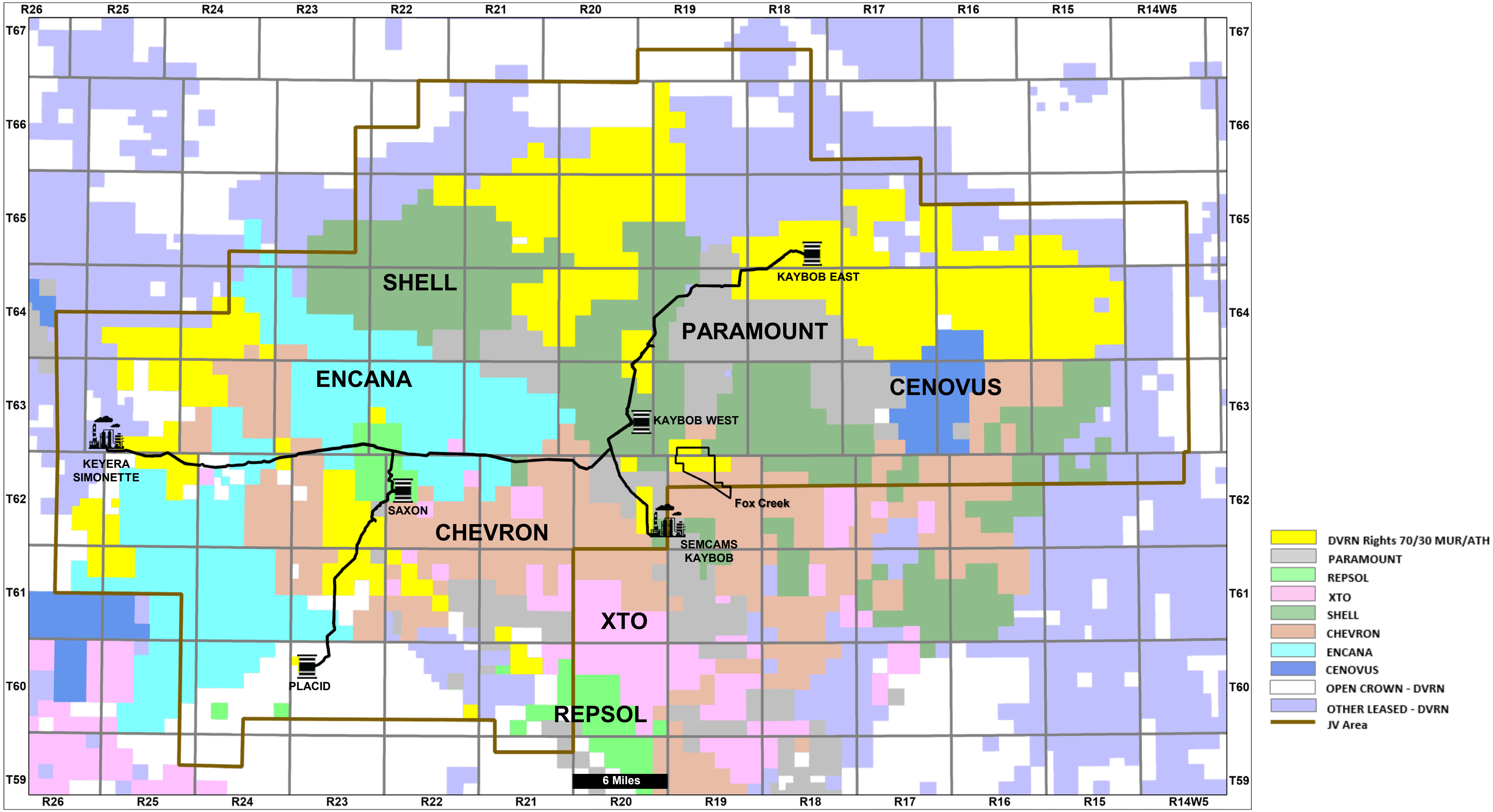


Eagle Ford Shale
Murphy Spacing vs Peers



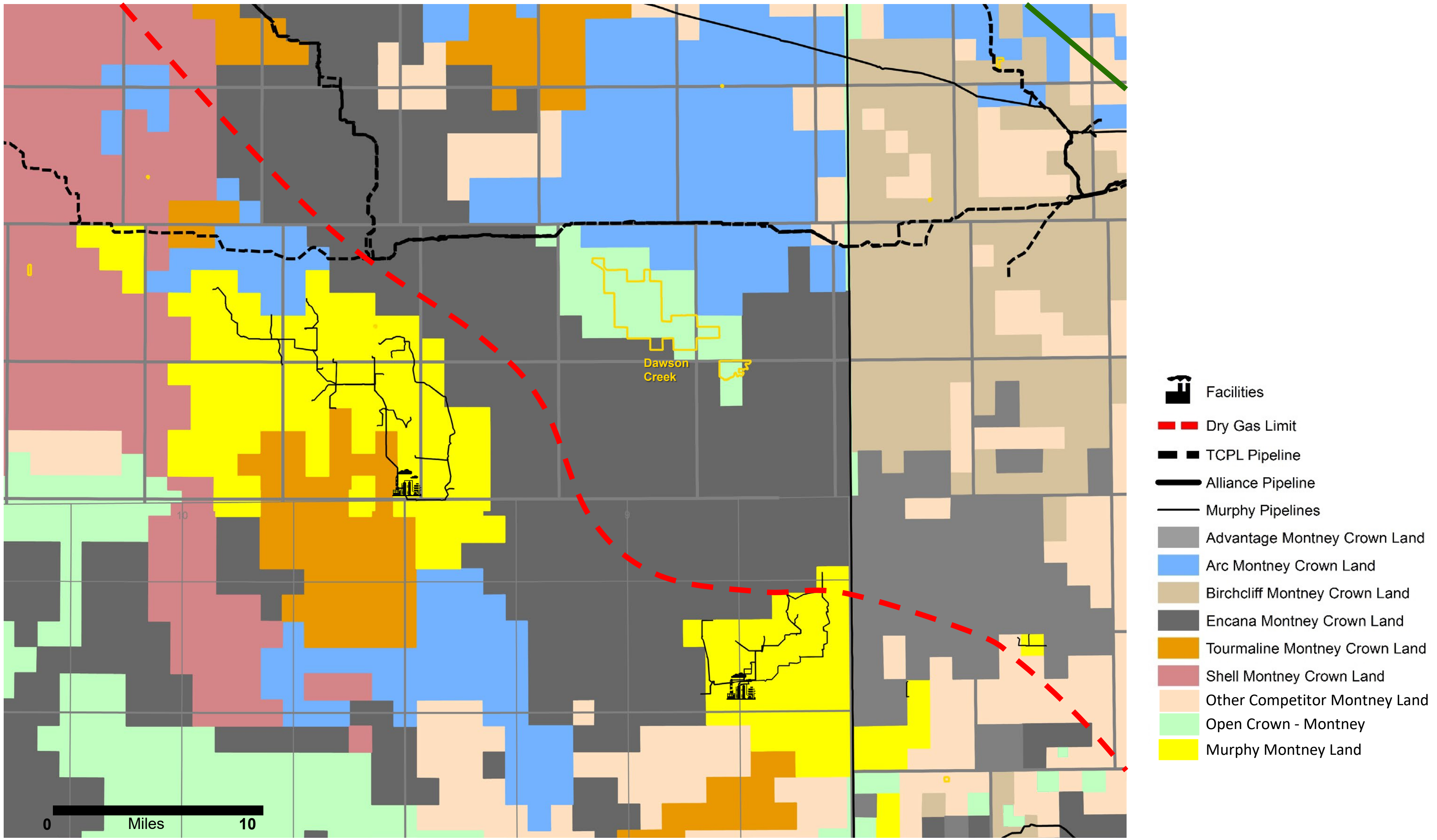
Kaybob Duvernay

Peer Acreage



Tupper Montney

Peer Acreage



Placid Montney

Peer Acreage