W&T OFFSHORE

38+ Years of Industry Leadership in the Gulf of Mexico

Bank of America Leveraged Finance Conference

December 1, 2021

Forward-Looking Statement Disclosure

This presentation, contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding our future operating and financial performance. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties, many of which are described under “Risk factors” in our Annual Report on From 10-K for the year ended December 31, 2020 available on our website and at www.sec.gov. You should understand that the following important factors, could affect our future results and could cause those results or other outcomes to differ materially from those expressed or implied in the forward-looking statements relating to: (1) amount, nature and timing of capital expenditures; (2) drilling of wells and other planned exploitation activities; (3) timing and amount of future production of oil and natural gas; (4) increases in production growth and proved reserves; (5) operating costs such as lease operating expenses, administrative costs and other expenses; (6) our future operating or financial results; (7) cash flow and anticipated liquidity; (8) our business strategy, including expansion into the deep shelf and the deepwater of the Gulf of Mexico, and the availability of acquisition opportunities; (9) hedging strategy; (10) exploration and exploitation activities and property acquisitions; (11) marketing of oil and natural gas; (12) governmental and environmental regulation of the oil and gas industry; (13) environmental liabilities relating to potential pollution arising from our operations; (14) our level of indebtedness; (15) timing and amount of future dividends; (16) industry competition, conditions, performance and consolidation; (17) natural events such as severe weather, hurricanes, floods, fire and earthquakes; and (18) availability of drilling rigs and other oil field equipment and services.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation or as of the date of the report or document in which they are contained, and we undertake no obligation to update such information. The filings with the SEC are hereby incorporated herein by reference and qualifies the presentation in its entirety.

Cautionary Note Regarding Hydrocarbon Quantities

The U.S. Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only 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, and on an optional basis, probable and possible reserves meeting SEC definitions and criteria. The company does not include probable and possible reserves in its SEC filings. This presentation includes information concerning probable and possible reserves quantities compliant with PRMS/SPE guidelines and related PV-10 values that may be different from quantities of such non-proved reserves that may be reported under SEC rules and guidelines. In addition, this presentation includes Company estimates of resources and “EURs” or “economic ultimate recoveries” that are not necessarily reserves because no specific development plan has been committed for such recoveries. Recovery of estimated probable and possible reserves, and estimates of resources and EUR’s and recoverable resources, are inherently more speculative than recovery of proved reserves.

Corporate Summary & Update

Proven and Consistent Strategy

Focus on Free Cash Flow Generation

Prioritize Environmental, Social and Governance Matters

Maintain High Quality Conventional Asset Base with Low Decline

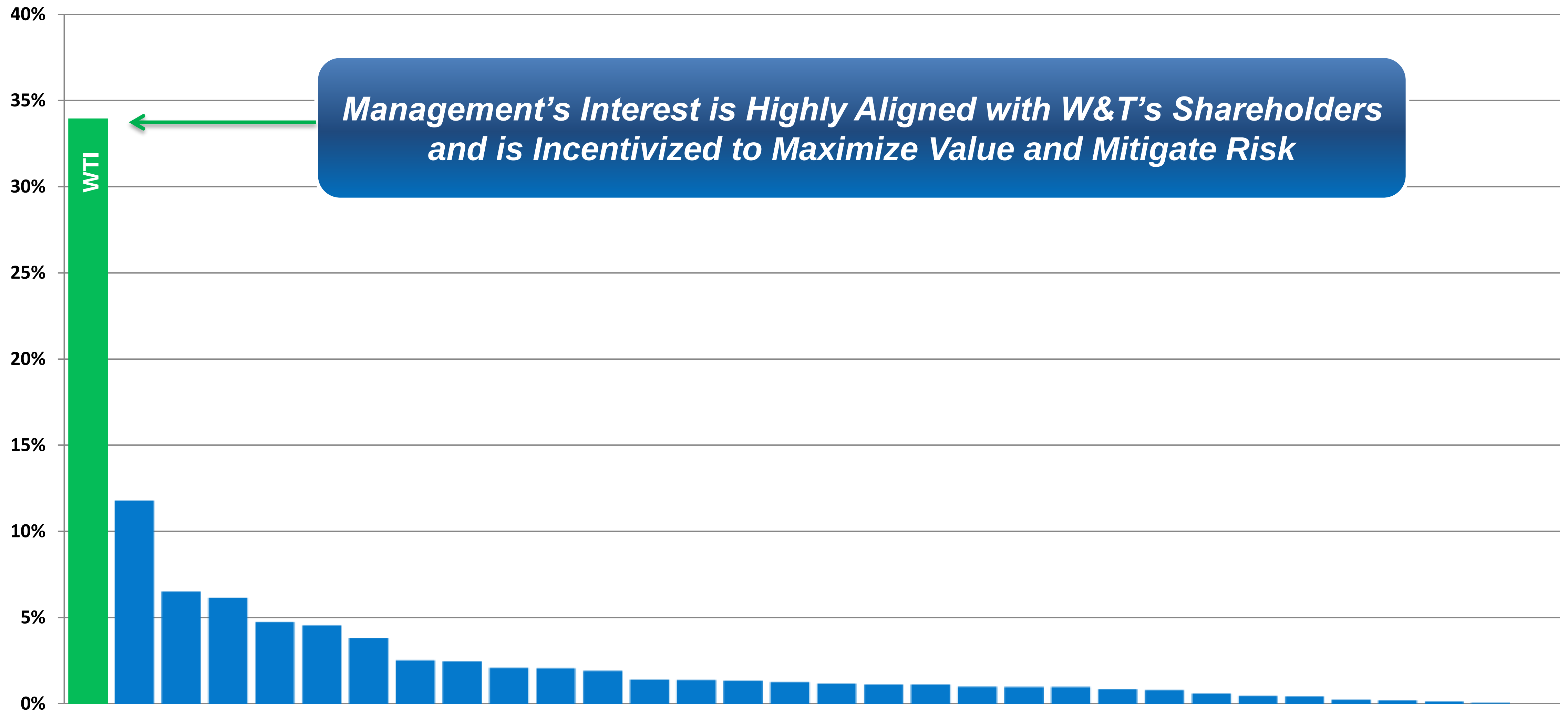
Reduce Costs to Improve Margins and Increase ROCE

Preserve Ample Liquidity and Financial Flexibility

Capitalize on Unique and Accretive Opportunities

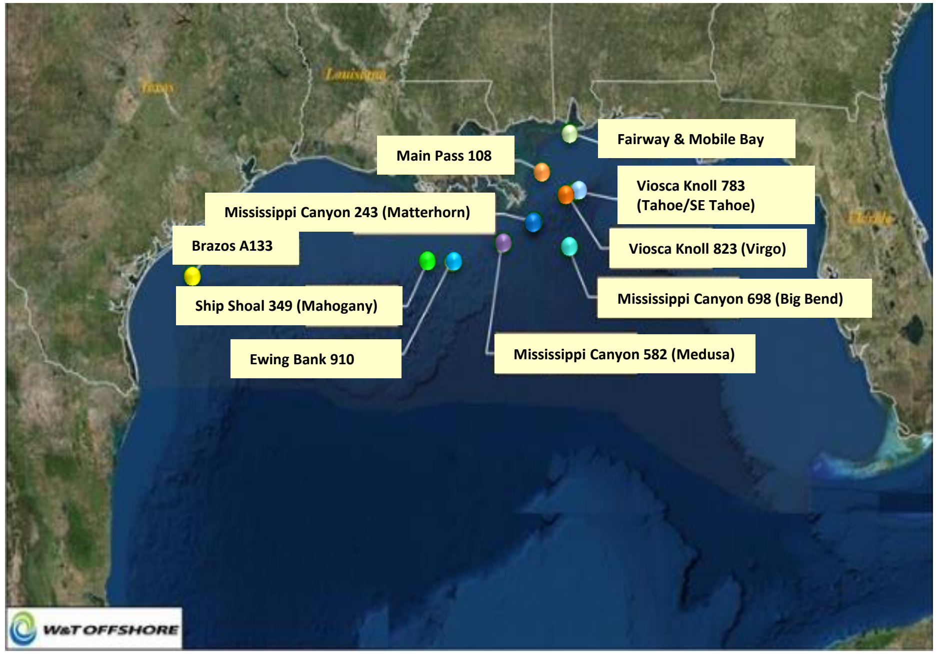
Management Ownership[1]

Among the Highest of Public E&P Companies[2]



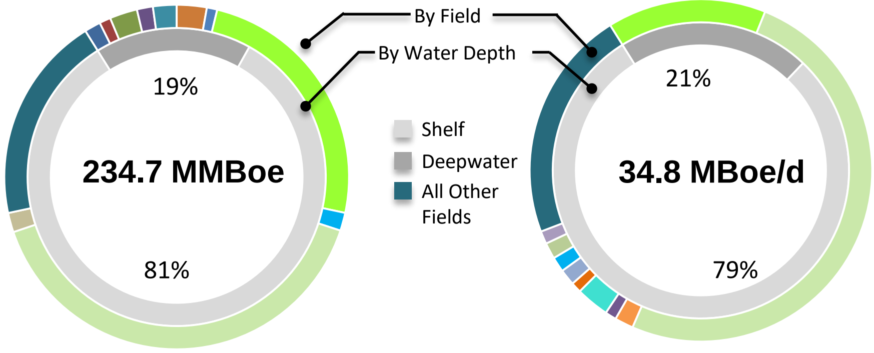
1) Ownership percentage of Named Executive Officers from 2021 company proxies, Data sources include Irwin, Bloomberg & Company filings.
2) Companies sorted alphabetically: AR, BCEI, BRY, BTE, CDEV, CNX, COG, CPE, CPG, CRK, ESTE, GDP, KOS, LPI, MCF, MGY, MRO, MTDR, MUR, NOG, PDCE, PVAC, REI, RRC, SBOW, SD, SM, SWN, TALO.

Company Snapshot



2P Reserves Mix[3]

3Q21 Avg. Daily Production[2]



3Q21 Average Production:	34.8 MBoe/d (46% liquids)
Producing Fields	41
Adjusted EBITDA[1]	9/30/21 YTD $152.6 MM
Free Cash Flow[1]	9/30/21 YTD $66.3 MM

Net Mid-Year Reserves (MMBoe)	SEC Pricing[3]	NYMEX Strip[4]
1P	158.9	165.7
2P	234.7	243.1
3P	337.7	347.0

Gulf of Mexico Shelf

- ~416,000 gross acres (~331,000 net)
- 79% of 3Q21 production of 34.8 MBoe/d
- Proved reserves of 139.8 MMBoe[4]
- 2P reserves of 194.9 MMBoe[4]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

- ~187,000 gross acres (~77,000 net)
- 21% of 3Q21 production of 34.8 MBoe/d
- Proved reserves of 26.0 MMBoe[4]
- 2P reserves of 48.2 MMBoe[4]
- Substantial upside with existing acreage

Federal vs State

- Production: Federal 60%, State 40%
- Net Acreage: Federal 78%, State 22%

Premium GOM Operator with 38+ Years of History in the Basin

Note: The outer ring of the pie charts represent contribution by field, with color indicating field location on the map.
1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see Appendix for description of reconciling items to GAAP net income.
2) Breakout between Deepwater and Shelf reflects total Company production.
3) Based on mid-year 2021 reserve report by NSAI at average realized SEC pricing (1P Life) of $47.78/BO and $2.50/MMbtu.
4) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96/MMbtu.

NYSE: WTI

Recent Highlights

3Q21 Production

- Produced **34.8 MBoe/d**, or 3.2 MMBoe (46% liquids) in 3Q21 despite the impact of Hurricane Ida

9/30/21 YTD Free Cash Flow[1]

- Produced Free Cash Flow of **$66.3** million in the first nine months of 2021

9/30/21 YTD Adjusted EBITDA[1]

- Generated Adjusted EBITDA of **$152.6** million in the first nine months of 2021

✓ **Net Debt down over $200 million, or 29%, from quarter ended December 31, 2019 to September 30, 2021**

✓ **Enhanced capital structure in May 2021 with $215 million non-recourse first-lien loan**

- Substantially increased cash balance and paid off then outstanding RBL balance

✓ Increased SEC proved reserves by 10% to 158.9 MMBoe[3] at mid-year 2021, representing a reserve replacement ratio of nearly 300% of production for the first half of 2021 and 165.7 MMBoe[4] using July 1, 2021 NYMEX strip pricing

- PV-10 of SEC mid-year 2021 proved reserves increased 39% to $1.0 billion[2,3]
- PV-10 of NYMEX mid-year 2021 proved reserves increased 36% to $1.5 billion[2,4]

✓ Reaffirmed 2021 capital spending of $30 to $60 million

✓ Announced participation in drilling of a high potential, lower risk deepwater exploratory prospect in the Mississippi Canyon area

✓ Continued focus on Environmental, Social and Governance (“ESG”) initiatives

- Reduced GHG emissions through consolidation Mobile Bay treating facilities in early 2021
- Strong diversity of executive officers and board members with 50% women/minorities
- Implemented changes to better align employee and executive compensation with ESG
- **Received recognition of improved ESG practices from a key rating agency, which upgraded our rating to the top third of oil and gas producers rated**

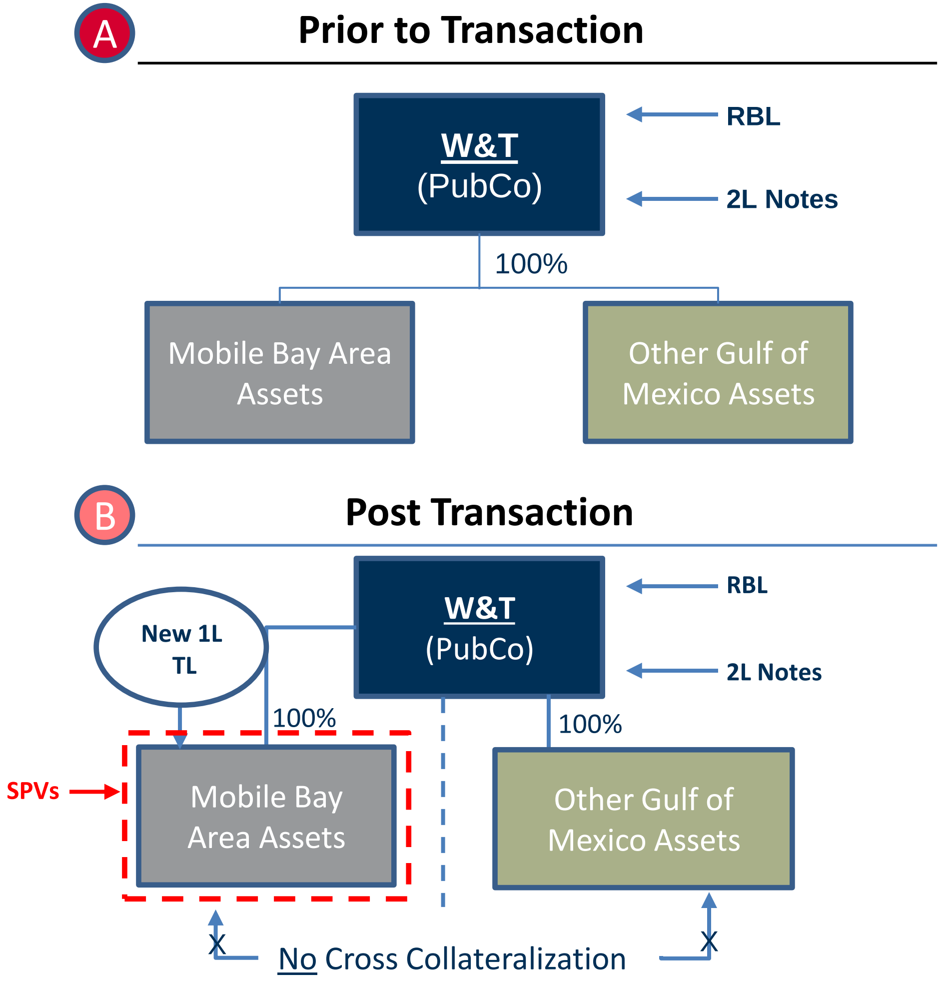
Continued Focus on Delivering Free Cash Flow and Adding Value

1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see Appendix for description of reconciling items to GAAP net income.
2) Before consideration of cash outflows related to asset retirement obligations.
3) Based on mid-year 2021 reserve report by NSAI at average realized SEC pricing (1P Life) of $47.78/BO and $2.50/MMbtu.
4) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96/MMbtu.

Mobile Bay Transaction Overview

- ✓ Partnered with Munich Re, a reputable AA-rated counter-party, to fund future growth needs
  - Potential to scale over time to finance additional acquisitions
- ✓ Increased cash on hand with non-recourse financing
- ✓ Leverage-neutral transaction in non-recourse SPV structure
  - No maintenance covenants or redetermination requirements and no covenants at the parent level or recourse to any other assets of parent
- ✓ Term loan interest rate of 7% is at a substantially lower level compared to recent GOM high yield deals
  - Mandatory amortization over 7 years supports deleveraging
  - Executed natural gas derivatives contracts through term of loan to cover debt service
  - Only cash flows from the Mobile Bay area asset will be used to service the term loan debt going forward
- ✓ W&T owns 100% of the equity in the SPVs
  - Keeps all cash flows associated with the Mobile Bay area assets after debt service and reserves
  - Adds cash to the balance sheet to reinvest in accretive acquisitions or other accretive drilling opportunities
  - Keeps future drilling opportunities
- ✓ On a consolidated basis, all earnings and debt are reported at the W&T level, public filings will reflect all activity for W&T and the SPVs

Corporate Structure



Boosted Cash and Allowed Repayment of the RBL Facility

Capital Structure as of September 30, 2021

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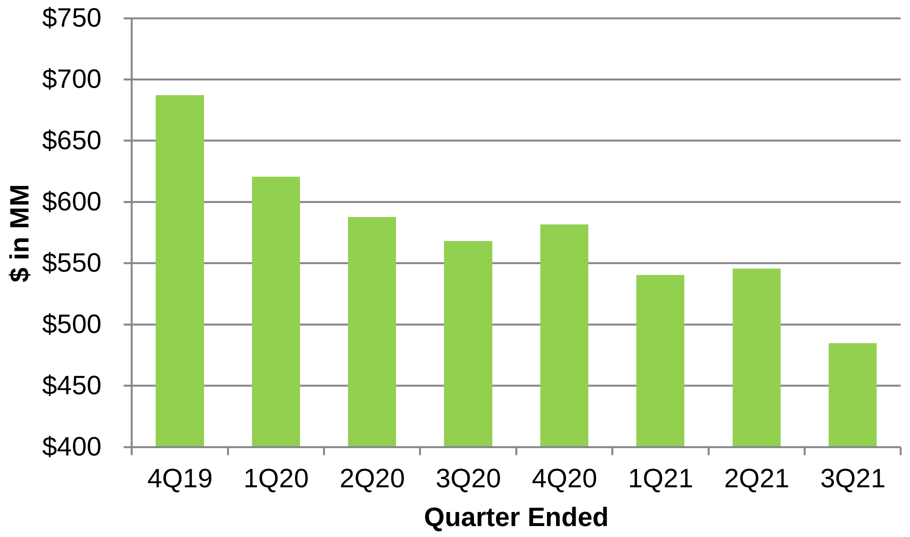
Net Debt[1] as of 9/30/21 ($ in millions)

Total Cash & Equivalents	**$257.6**
9.75% 2nd Lien Notes due Nov. 2023	$547.0
RBL Borrowings[2]	-
7% Non-recourse Term Loan due 2028	$195.4
Total Debt[3]	**$742.4**
Net Debt[1]	**$484.8**

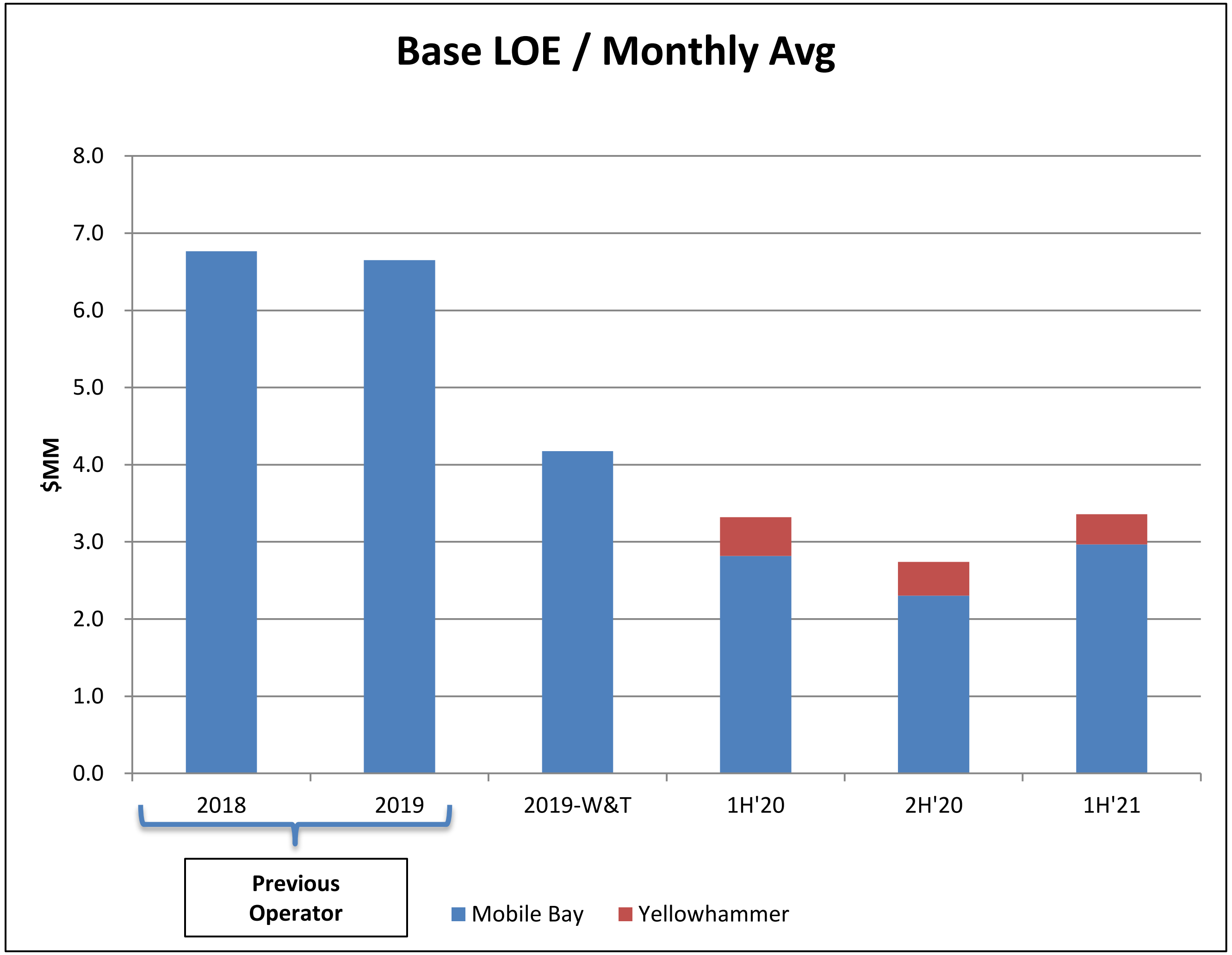
Net Debt[1] Over Time



- ✓ Proven track record of generating free cash flow and prudently managing the balance sheet through multiple price environments
- ✓ Despite a difficult 2020 with COVID-19, negative oil prices, and hurricane impacts, **W&T reduced net debt by $202 MM** from December 31, 2019 to September 30, 2021
  - $73 million of Second Lien notes were opportunistically repurchased for only $24 million in cash in early 2020
- ✓ Recent Mobile Bay transaction **substantially increased W&T's cash balance** with non-recourse debt financing
  - First Lien secured term loan is non-recourse to W&T at the parent level and is amortized over seven years at a fixed interest rate of 7%
  - Provides significant source of funds for acquisitions and other growth opportunities
- ✓ **Calculus Lending, LLC facility replaces traditional RBL**
  - New $100 million revolving credit facility with $50 million borrowing base provides opportunistic liquidity
  - W&T stepped away from conventional RBL market given less flexible and more onerous terms being required by banks in recent years

1) Net Debt is defined as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents.
2) RBL borrowings exclude $4.4 MM of outstanding letters of credit.
3) Total Debt includes unamortized debt discounts.

Mobile Bay Case Study



"Mobile Bay" Fields

- WI: 25% - 100%, 10' - 50' water depth
- Purchased in 2019
- $168MM acquisition cost
- Valuation
  - Total Net Cash Flow[1] $84MM
  - Mid-year 2P PV10 net of ARO $440MM
  - **Total Project Value[2] $524MM**
- Have increased value by:
  - Consolidation of treatment facilities in the area
  - Modify treatment of waste oil
  - Reducing downtime

Current Reserves[3]

1P Reserves:	81.8	MMBoe
2P Reserves:	92.9	MMBoe
3P Reserves:	100.4	MMBoe

1) From final purchase price including capex to June 30, 2021.
2) Total Net Cash Flow as of June 30, 2021, plus Mid-year 2021 2P PV10 (including ARO).
3) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu.

Environmental, Social and Governance

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Disclosure & Reporting Framework

- SASB (Sustainability Accounting Standards Board)
- TCFD (Task Force on Climate-related Financials Disclosures)
- SDG (Sustainable Development Goals)

Environmental

- Committed to protecting and preserving the environment
- Robust program of policies and continuous training
- Focused on best practices and strategies to reduce emissions
- **In 2021 consolidated 2 Mobile Bay treating facilities into one plant reducing emissions**
- **Spill Ratio[1]: W&T's ratio in 1H'21 was 0.03**

Social

- Focused on our organization and our communities
- Organization focused on open communication and trust to build a strong culture
- Continuous professional development of our workforce and safety performance
- **50% of our executive officers and board members are women or minorities**
- **Required diversity training throughout organization**

Governance

- Strong Board oversight responsible for strategy, governance and creating long-term value
- Highest legal and ethical standards expected across entire organization
- Focused on being a responsible corporate citizen with policies and procedures
- **New board member elected in May 2021**
- **Employee and Executive Compensation tied to ESG performance metrics**

Received Recognition of Improved ESG Practices From A Key Rating Agency Which Upgraded Our Rating to the Top Third of Oil and Gas Producers Rated

1) Spill Ratio: Barrels spilled / millions of barrels produced

Note: Additional details on our 2020 ESG report and initiatives can be found on the W&T website: https://www.wtoffshore.com/corporate-responsibility

Mid-Year 2021 Reserve Report at SEC Pricing[1]

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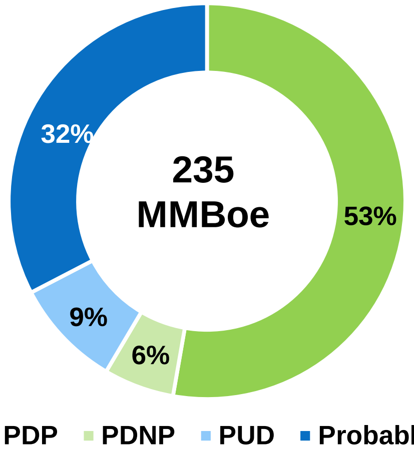
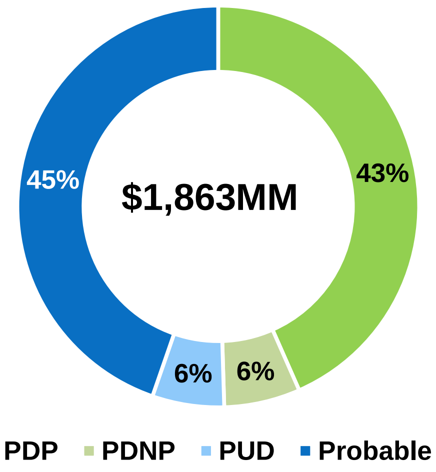
Reserve Category	Oil (MMBoe)	NGL (MMBoe)	Gas (Bcf)	Total (MMBoe)	% Liquids	Pre-Tax[2] PV-10 ($MM)
Proved Developed Producing (PDP)	23.0	17.2	505.3	124.4	32.3%	$808
Proved Developed Non-Producing (PDNP)	4.5	1.1	48.0	13.6	41.0%	$114
Proved Undeveloped (PUD)	9.8	1.6	57.2	20.9	54.4%	$108
Total 1P Reserves (Excluding ARO)	**37.3**	**19.8**	**610.5**	**158.9**	**36.0%**	**$1,031**
Probable Reserves (PROB)	35.1	7.0	202.7	75.8	55.4%	$833
Total 2P Reserves(Excluding ARO)	**72.4**	**26.8**	**813.2**	**234.7**	**42.3%**	**$1,863**
Possible Reserves (POSS)	54.1	8.4	243.1	103.0	60.6%	$1,409
Total 3P Reserves (Excluding ARO)	**126.5**	**35.1**	**1,056.4**	**337.7**	**47.9%**	**$3,272**

2P SEC Reserves[1]



Natural Gas 57.7%
Liquids 42.3%

2P Pre-Tax PV-10[2,3]



1) Based on mid-year 2021 reserve report at average realized SEC pricing of $47.78/BO and $2.50MMbtu.
2) Pre-Tax PV-10 is a non-GAAP measure; see reconciliation in Appendix.
3) Pre-Tax PV-10 excluding 1P Asset Retirement Obligation.

Reserves: 7/1/21 NYMEX Strip Pricing[1]

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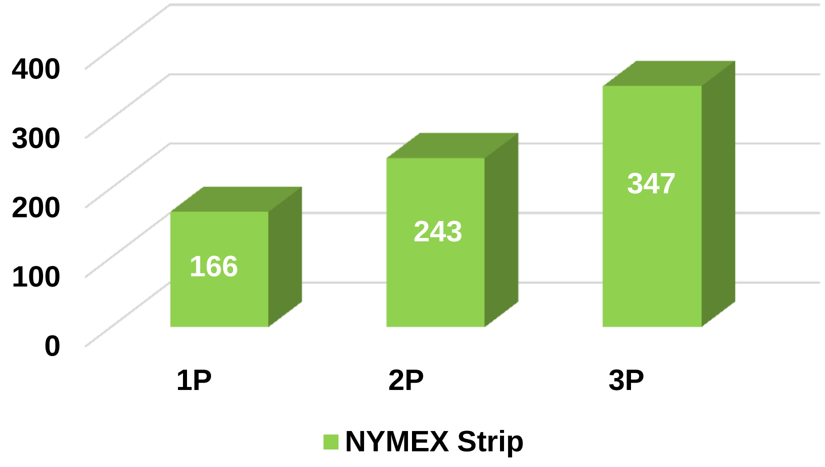
Mid-Year 2021 Reserve Report Summary - 07/01/21 NYMEX Strip Pricing

Reserve Category	Oil (MMBoe)	NGL (MMBoe)	Gas Bcf	Total (MMBoe)	% Liquids	Pre-Tax PV-10
Proved Developed Producing (PDP	23.3	18.1	531.4	129.9	31.8%	$1,157
Proved Developed Non-Producing (PDNP)	4.8	1.1	54.4	14.9	39.1%	$160
Proved Undeveloped (PUD)	9.8	1.6	57.2	20.9	54.4%	$201
Total 1P Reserves (Excluding ARO)	**37.8**	**20.7**	**643.0**	**165.7**	**35.3%**	**$1,519**
Probable Reserves (PROB)	35.3	7.1	210.0	77.4	54.8%	$1,035
Total 2P Reserves Excluding ARO)	**73.1**	**27.8**	**853.0**	**243.1**	**41.5%**	**$2,554**
Possible Reserves (POSS)	54.2	8.5	246.9	103.9	60.4%	$1,678
Total 3P Reserves Excluding ARO)	**127.3**	**36.3**	**1,099.9**	**347.0**	**47.2%**	**$4,232**
1P Asset Retirement Obligation ("ARO")						($207)

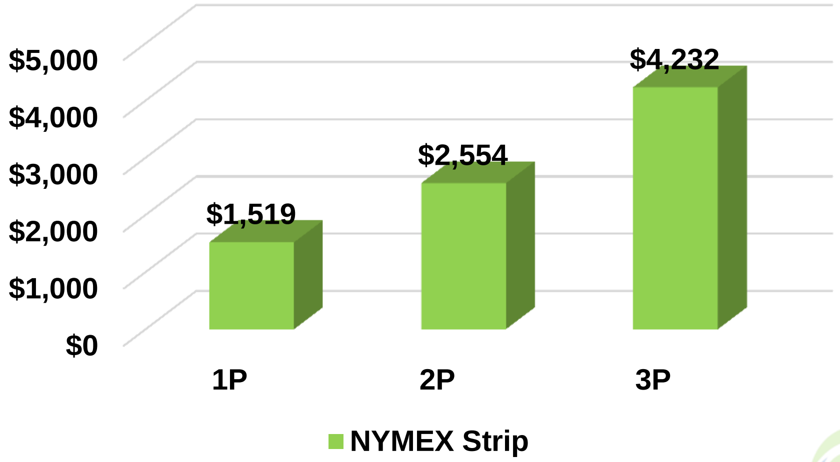
7/1/21 NYMEX Strip Prices (1P Life)

Oil $/Bbl	Gas $/MMbtu
$57.80	$2.96

Reserves MMBoe



Reserves PV-10 $MM



1) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu

Strategic Capital Allocation Plan

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Organic Projects

Focus on high rate of return projects and fields with multiple drilling opportunities that can generate cash flow quickly. Utilize GOM expertise and new technologies to identify and develop projects. Evaluate potential for joint venture funding.

Asset Acquisitions

Pursue compelling producing assets generating cash flow at attractive valuations with upside potential and optimization opportunities.

Debt Pay Down

Use free cash flow to reduce debt, optimize the balance sheet and maintain financial flexibility.

Generate Shareholder Value

Maintain a Prudent Balance Sheet and Use Free Cash Flow to Grow Opportunistically and Reduce Debt

Operational Overview

Why We Have Liked the Gulf of Mexico for the Last 40 Years

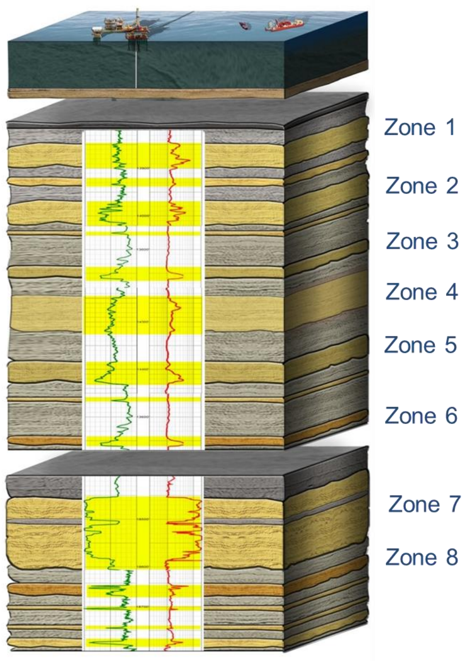
GOM Provides Better Porosity and Permeability than the Unconventionals

Multiple stacked pay opportunities

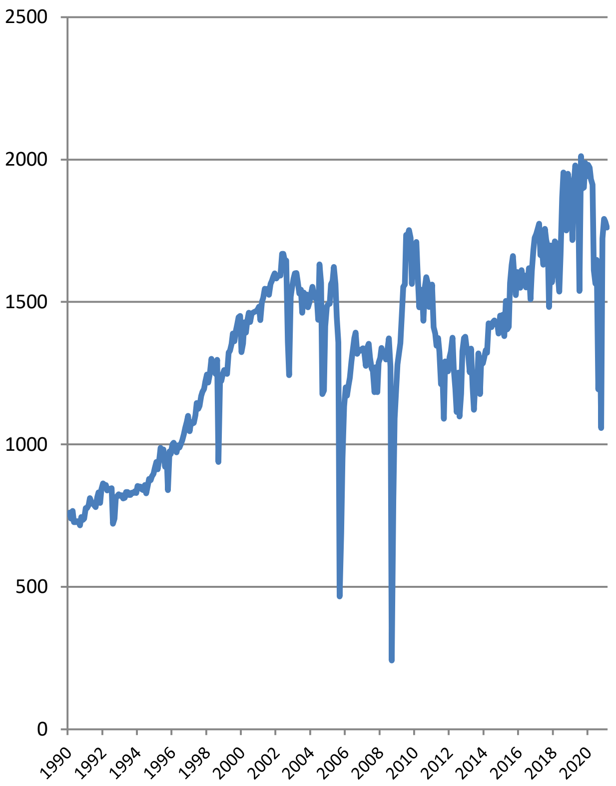
- Offer attractive primary production and recompletion opportunities
- Provide multiple targets improving chance of success when drilling

Natural drive mechanisms generate incremental production from 2P and 3P reserves

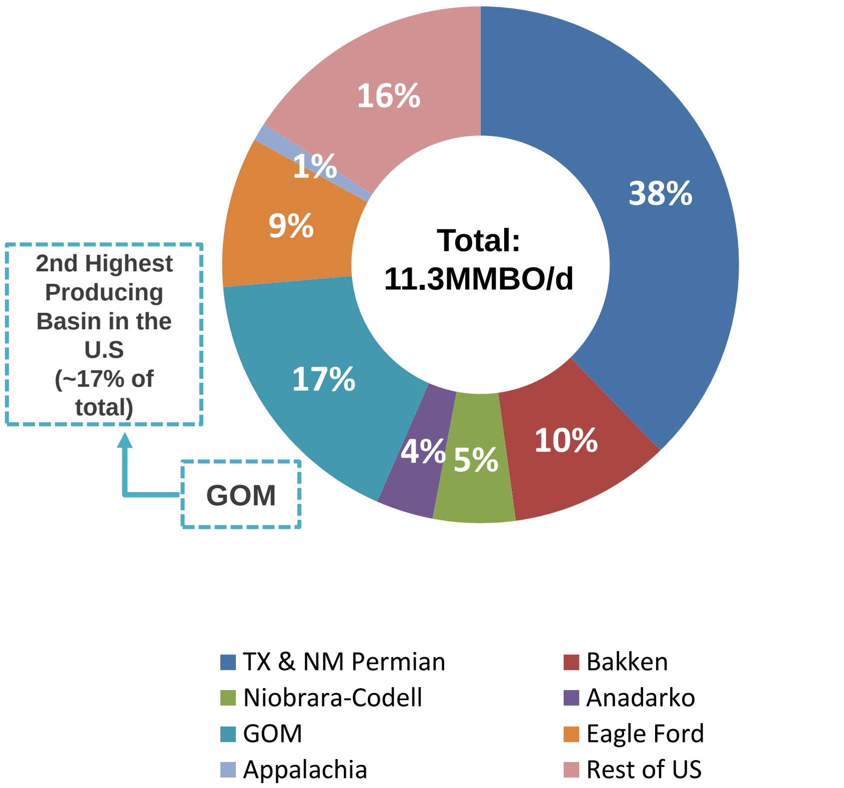
- High quality sandstones have drive mechanisms superior to depletion drive alone
- Enjoy incremental reserve adds, partly due to how reserve quantities are booked or categorized under SEC guidelines



GOM Historical Oil Production[1]



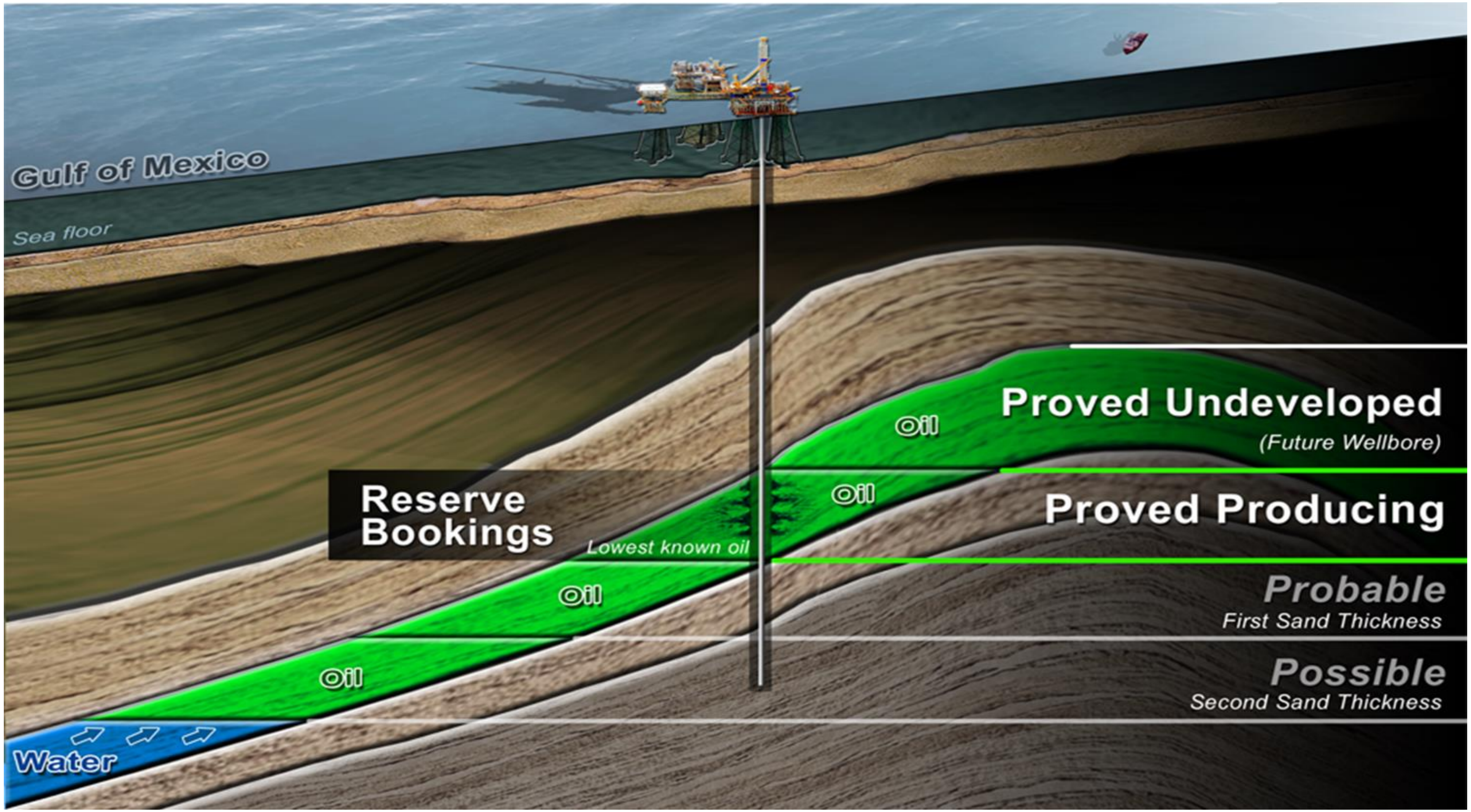
US Oil Production by Key Region[1]



GOM Provides Unique Advantages:
Low Decline Rates, World Class Porosity/Permeability and Significant Untapped Reserve Potential

1) Based on U.S. Energy Information Administration (EIA) data as of March 31, 2021.

Incremental Reserves May Be Produced at No Cost



Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

Realizing Incremental Reserve Upside[1]

Focused on Realizing the Reserves Upside and Adding Economic Value Across 3 Categories:

1 Prob + Poss Related to PDP

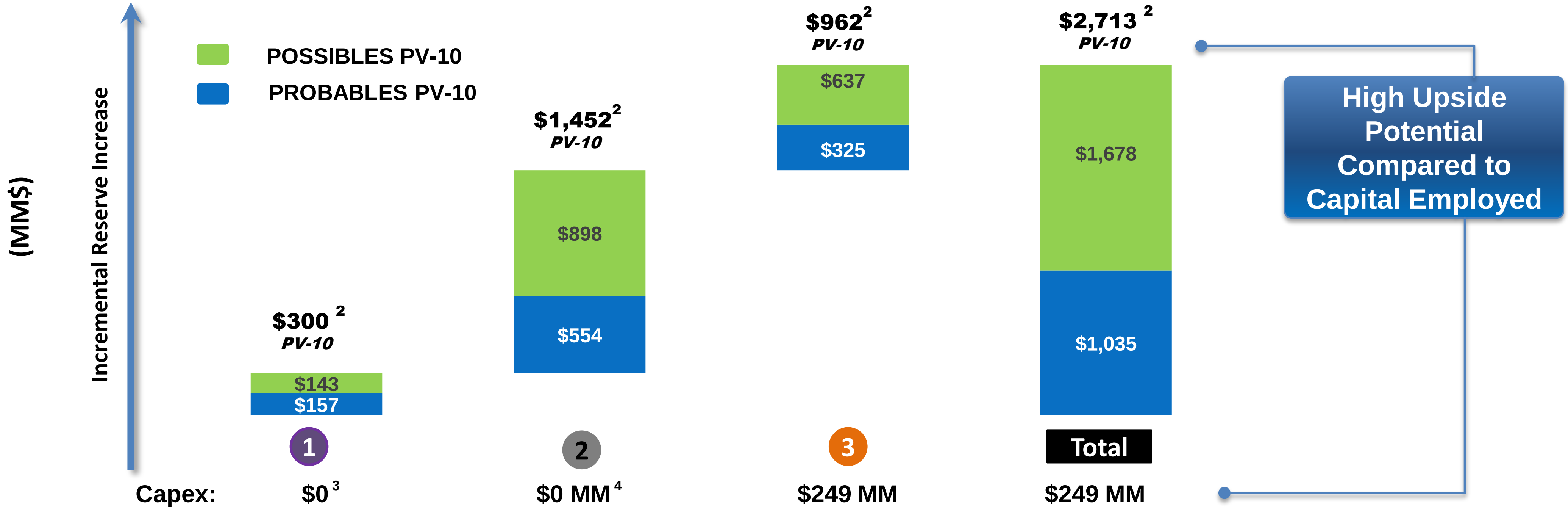
- No additional capex required
- Achievable because of WTI's demonstrated understanding of the fields

2 Prob + Poss Related to PDNP + PUD

- Contingent on execution of field development plans
- No incremental direct capex required
- Immediately moves to PDP upside (1) following proved capex spend

3 Prob + Poss Unrelated to 1P Reserves

- Additional capex required
- Limited step-out risk



1) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu.
2) Excludes Asset Retirement Obligation.
3) Probable and possible cases that are largely associated with producing wellbores and require no additional future CAPEX requirements.
4) Probable and possible reserves with no direct CAPEX requirements that are largely associated with PDNP and PUD reserves and therefore have associated future indirect CAPEX requirements.

Significant W&T Reserve Appreciation From Initial Bookings[1,2]

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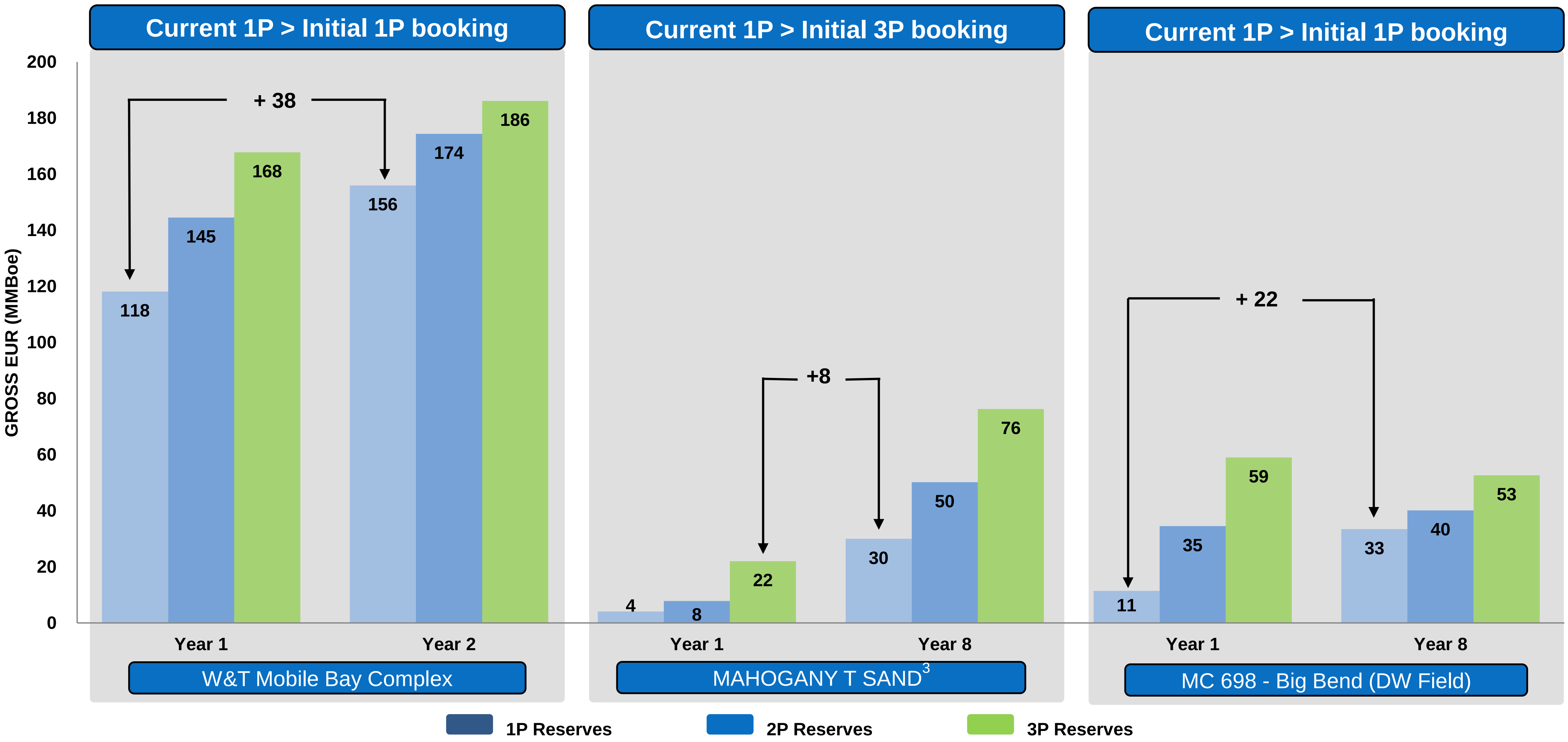

1) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu.
2) 1P = Proved, 2P = Proved + Probable, 3P = Proved + Probable + Possible.
3) Initial 1P booking includes A-14 well only; Mid-Year 2021 1P booking includes A-14, A-18 and A-19 wells; 2P & 3P includes additional development wells.

Leveraging 38+ Years of GOM Acquisition Expertise

ACQUISITION OPPORTUNITIES

GOM Exits

Companies exiting the GOM provide a large inventory of accretive assets

Asset Sales

Majors moving to ultra-deepwater and companies monetizing GOM assets to fund onshore projects

Consolidation Opportunities

Under-capitalized independents with sizeable undeveloped reserves

ACQUISITION CRITERIA

Generating Cash Flow

Strong current production rates with the opportunity to reduce operating expenses

Financeable

Large portion of reserve base is proved developed with solid probable/possible reserves

Identified Upside

Undrilled prospects, workover or recomplete opportunities, facility upgrades, secondary recovery projects

Gulf of Mexico Provides an Attractive, Large Acquisition Opportunity Set

History of Creating Long-Term Value from GOM Acquisitions[1]

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TOTAL

$115MM
Paid out in Aug. 2011

Net average production (1) of 1,373 Boe/d from Matterhorn and Virgo

Reserves (2):		
	1P –	**5.2 MMBoe**
	2P –	**9.8 MMBoe**
	3P –	**16.5 MMBoe**

NEWFIELD

$206MM
Paid out in Nov. 2014

Net average production (1) of 1,508 Boe/d from 78 offshore blocks, 65 of which are in deepwater

Reserves (2):		
	1P –	**1.4 MMBoe**
	2P –	**3.8 MMBoe**
	3P –	**8.1 MMBoe**

woodside

$55MM
Investments Post Acquisition
Paid out in Sep. 2019

Net average production (1) of 860 Boe/d from Neptune and 24 add'l blocks. One exploration well brought on production in 2014

Reserves (2):		
	1P –	**1.8 MMBoe**
	2P –	**2.1 MMBoe**
	3P –	**2.4 MMBoe**

Cobalt International Energy

$17MM
Paid out in Aug. 2018

Net average production (1) of 355 Boe/d from Green Canyon 859, 903, & 904

Reserves (2):		
	1P –	**0.2 MMBoe**
	2P –	**0.4 MMBoe**
	3P –	**0.6 MMBoe**

ConocoPhillips
Marubeni

$18MM
Paid out in Apr. 2021

Net average production (1) of 2,787 Boe/d from Garden Banks 783 & 784 (Magnolia Field)

Reserves (2):		
	1P –	**11.6 MMBoe**
	2P –	**21.3 MMBoe**
	3P –	**41.0 MMBoe**

2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021

Shell

$116MM
Paid out in Nov. 2012

Net average production (1) of 491 Boe/d from Tahoe and 6 other fields

Reserves (2):		
	1P –	**1.0 MMBoe**
	2P –	**1.2 MMBoe**
	3P –	**1.3 MMBoe**

Shell
Marubeni

$61MM
Paid out in Oct. 2014

Net average production (1) of 3,140 Boe/d from Fairway Field

Reserves (2):		
	1P –	**15.6 MMBoe**
	2P –	**17.2 MMBoe**
	3P –	**18.0 MMBoe**

CALLON PETROLEUM

$83MM
Investments Post Acquisition

Net average production (1) of 385 Boe/d from Medusa and 12 other fields

Two exploration wells brought on production in June 2015

Reserves (2):		
	1P –	**2.1 MMBoe**
	2P –	**3.7 MMBoe**
	3P –	**5.8 MMBoe**

ExxonMobil

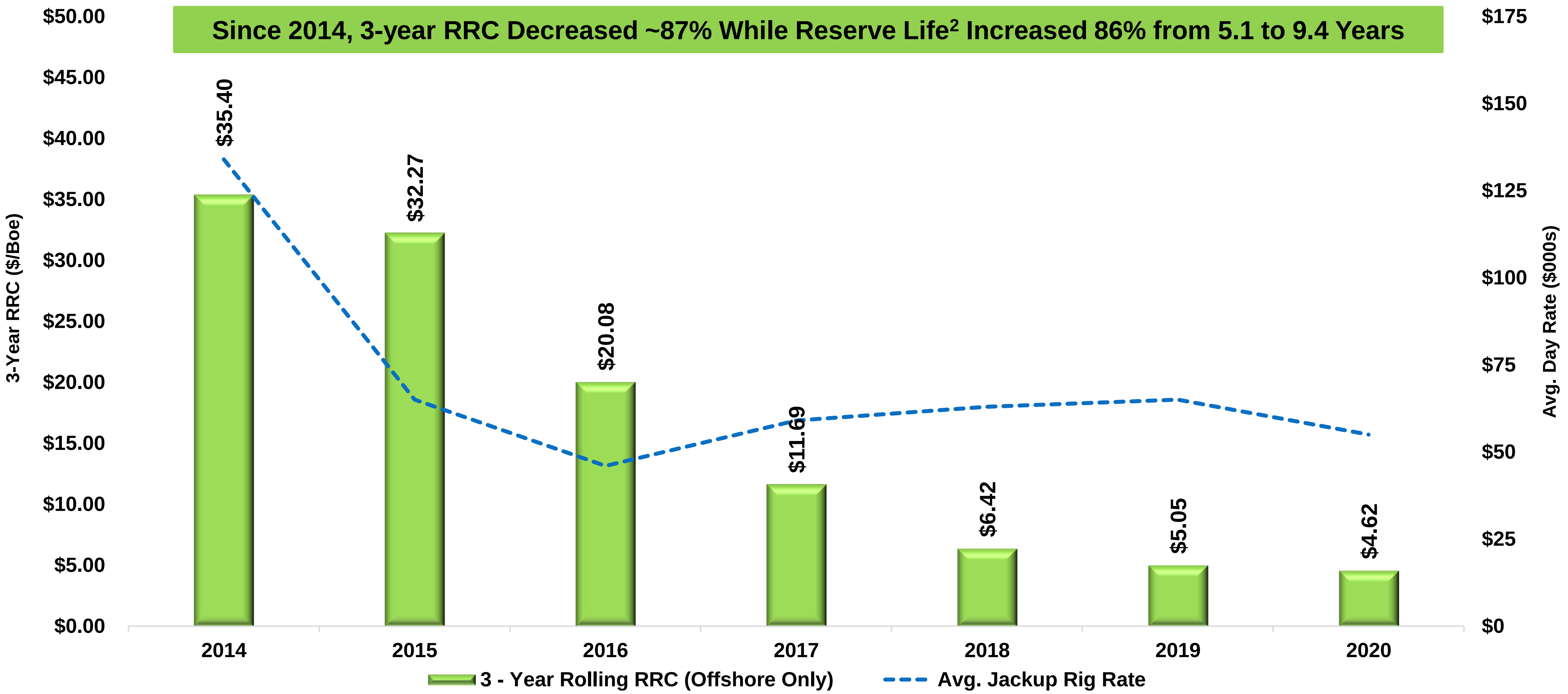
$168MM
Closed August 30, 2019

Net average production (1) of 15,331 Boe/d. Potential to add incremental reserves with minimal capital by consolidating operations with additional upside from potential future drilling locations and facility modifications

Reserves (2):		
	1P –	**81.8 MMBoe**
	2P –	**92.9 MMBoe**
	3P –	**100.4 MMBoe**

1) Reflects 2Q'21 net average production.
2) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu.

Significant Declines in All-In Reserve Replacement Cost[1] (RRC)

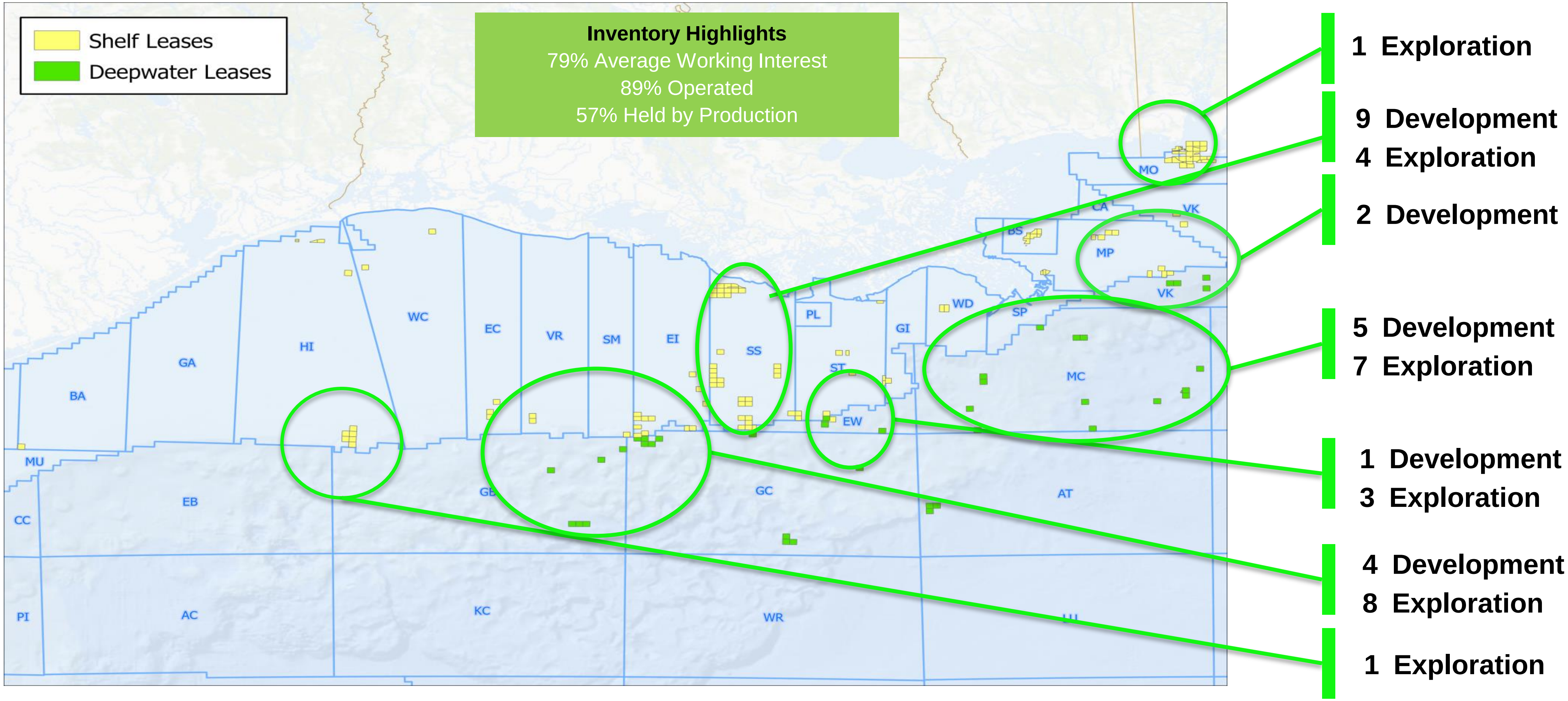


High Grading Projects, Sustainable Lower Service Costs, and Utilizing Existing Infrastructure Has Led to Lower RRC

1) Calculated as total capex divided by total reserve additions. Includes capital costs and reserves associated with revisions, extensions, discoveries and acquisitions.
2) Year-end Proved Reserves divided by production for the year.

Attractive Drilling Inventory[1]

Selected Growth Opportunities

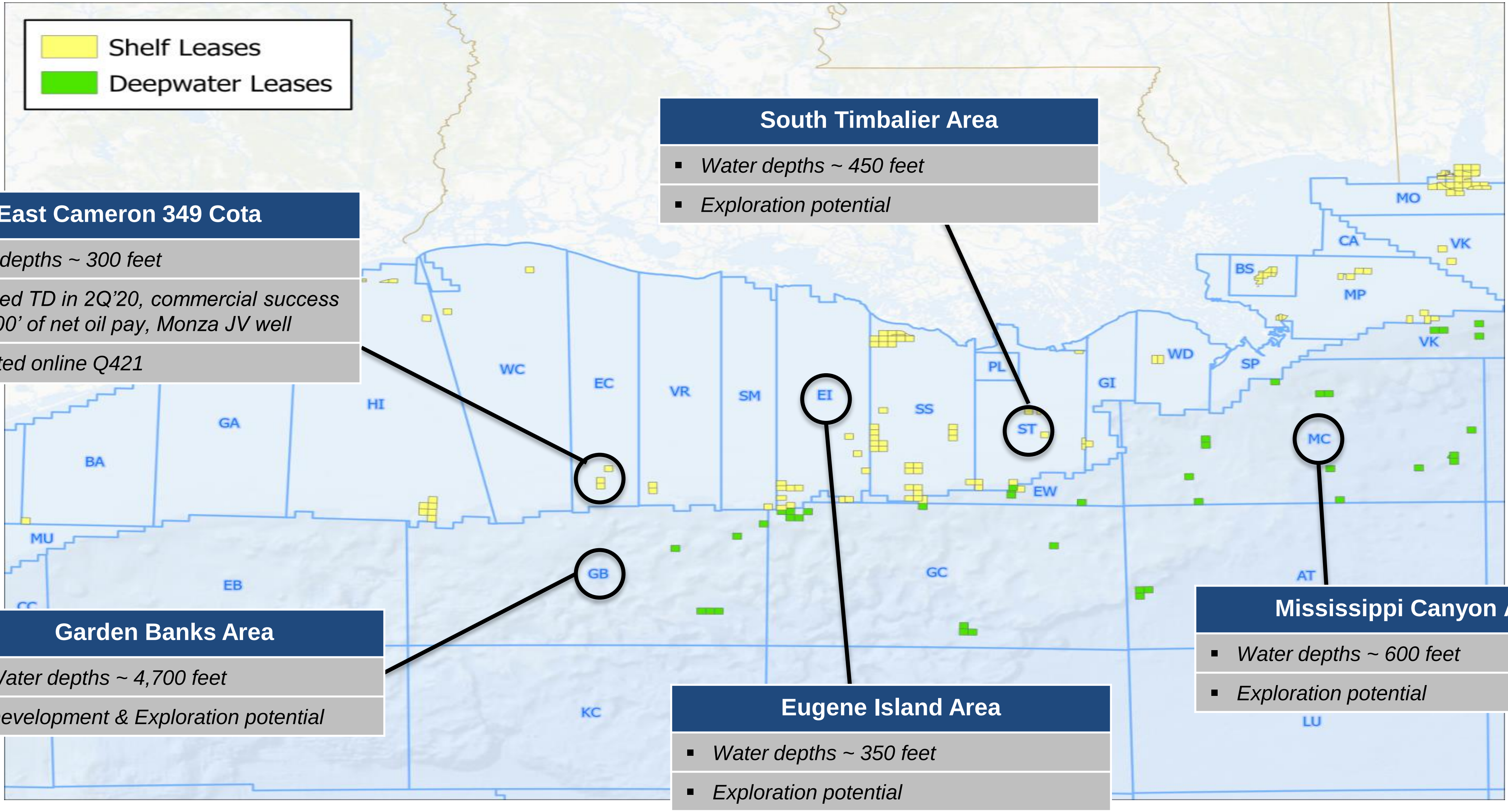


~45 Opportunities with 19 Platform Wells and 26 Subsea Tiebacks (all < 15 miles) with an Estimated 3P Resource Potential of ~200 MMBoe

1) Inventory as of November 2020.

Current Near-Term Prospects Under Evaluation

W&T OFFSHORE



South Timbalier Area

- *Water depths ~ 450 feet*
- *Exploration potential*

East Cameron 349 Cota

- *Water depths ~ 300 feet*
- *Reached TD in 2Q'20, commercial success with 100' of net oil pay, Monza JV well*
- *Expected online Q421*

Garden Banks Area

- *Water depths ~ 4,700 feet*
- *Development & Exploration potential*

Eugene Island Area

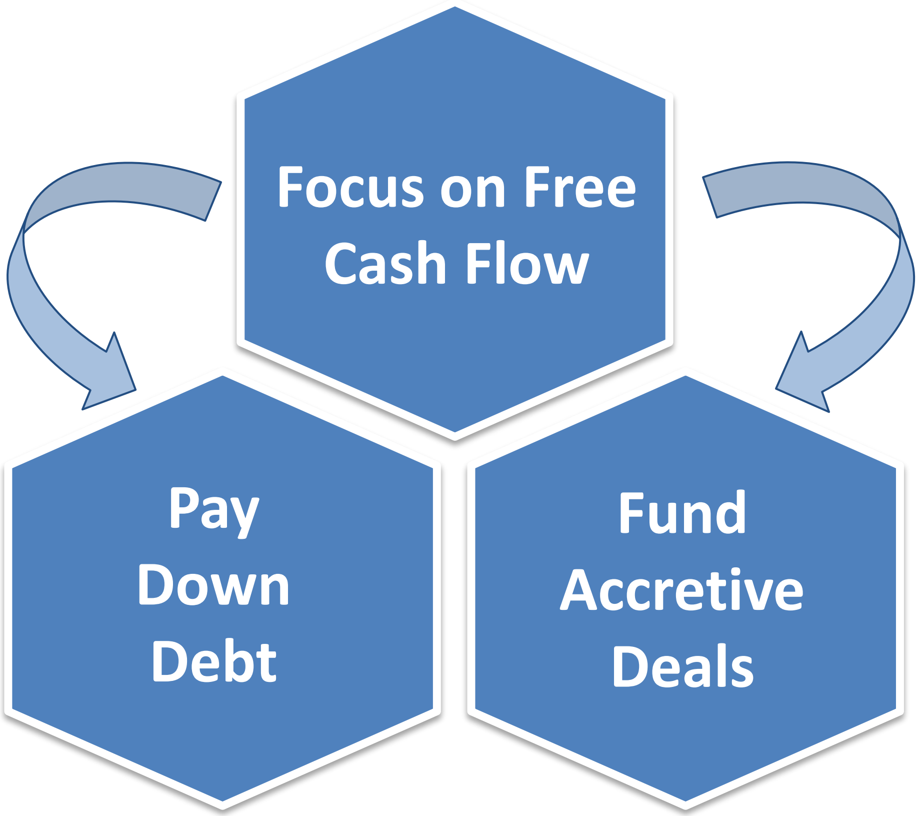
- *Water depths ~ 350 feet*
- *Exploration potential*

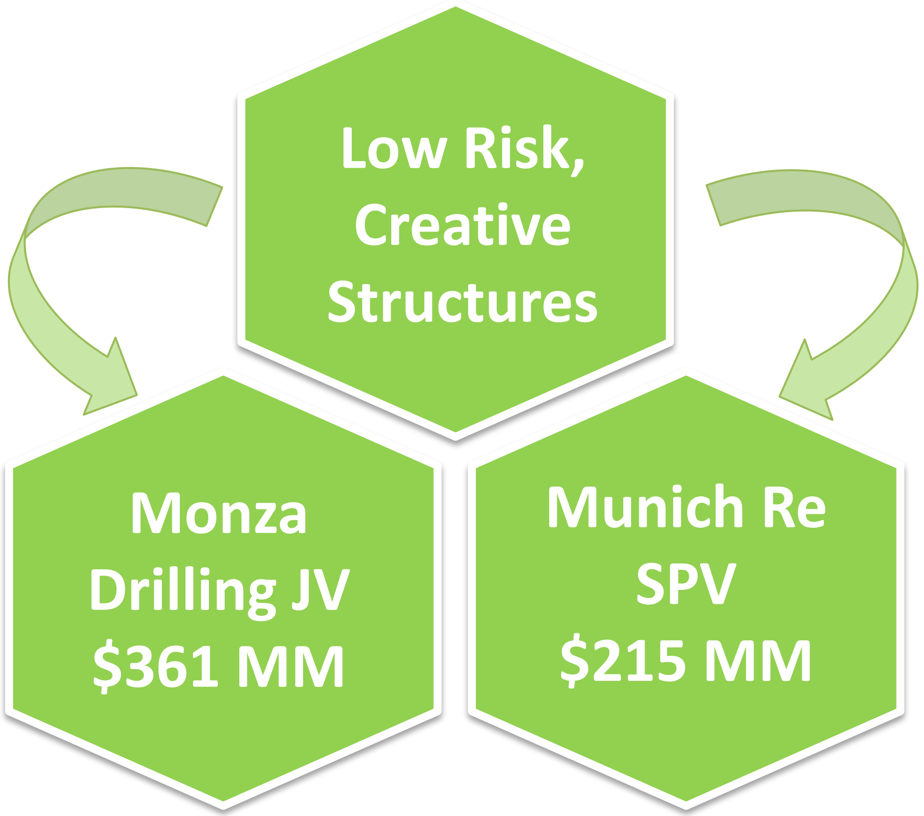
Mississippi Canyon Area

- *Water depths ~ 600 feet*
- *Exploration potential*

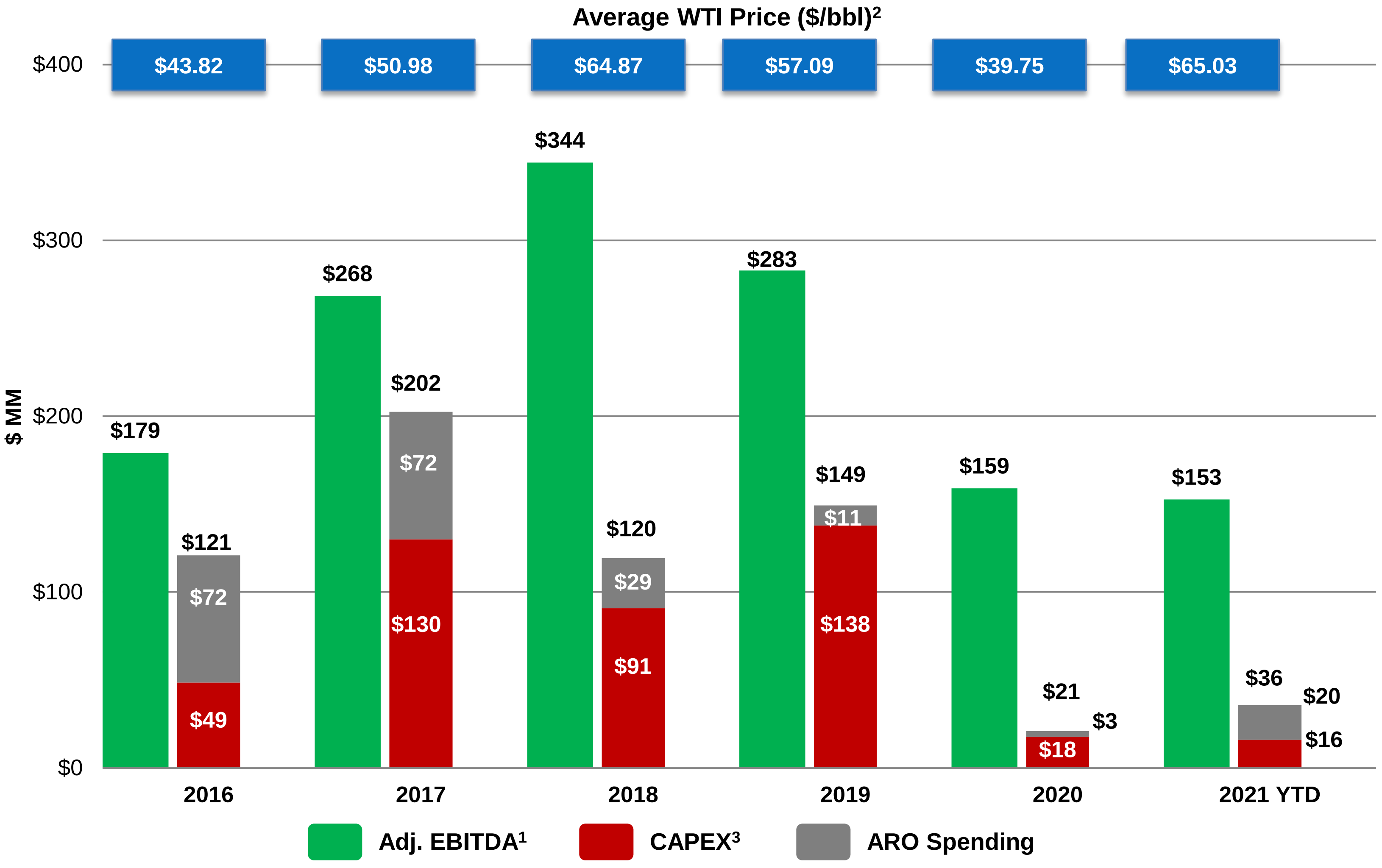
Financial Overview

Financial Strategy





Generating Significant Free Cash Flow[1]

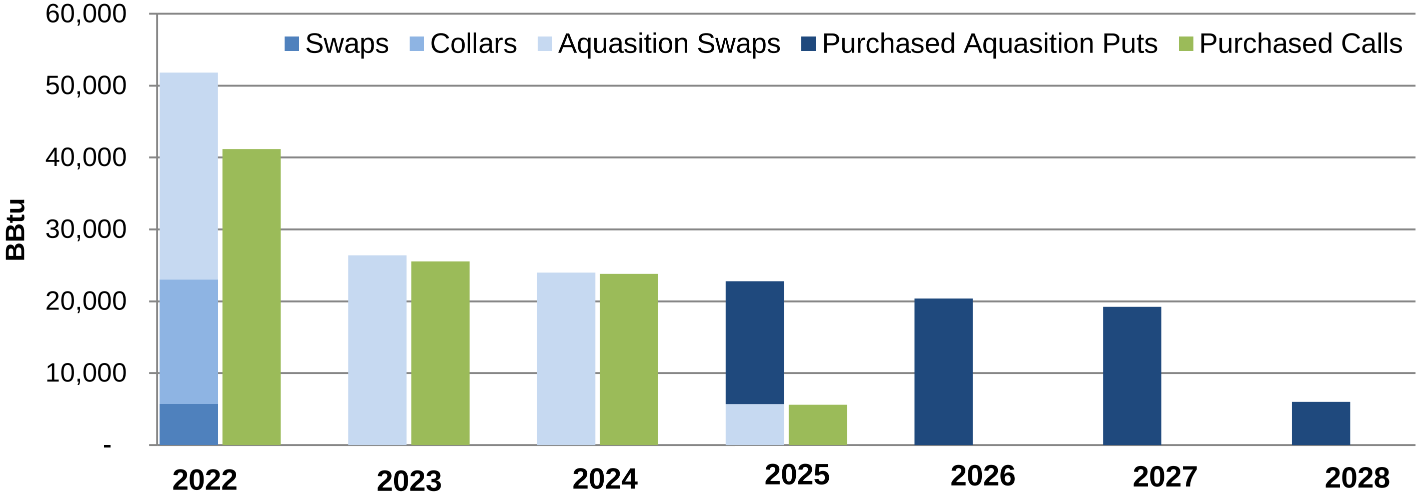


- ✓ Strong production base and cost optimization delivers steady Adjusted EBITDA[1]
- ✓ Adjusted EBITDA[1] has materially outpaced CAPEX and ARO spending (excluding acquisitions) since 2016
- ✓ In 2020, utilized portion of cash generated to reduce 2nd Lien debt by $72.5 MM through bond repurchases at ~33% of par value

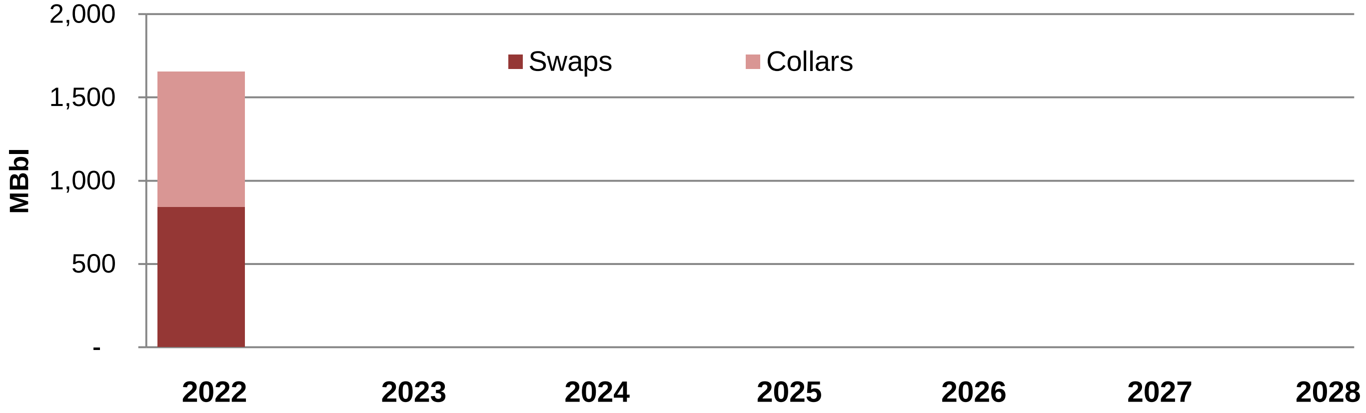
1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see Appendix for description of reconciling items to GAAP net income.
2) Source: Capital IQ.
3) Capex excludes acquisitions; includes only accrual basis capital expenditures.

Hedge Program (as of November 30, 2021)

Natural Gas Hedges



Oil Hedges



Natural Gas

- ✓ Mobile Bay transaction required gas hedges at the SPV level to cover a majority of debt service
- ✓ W&T structured "synthetic long puts" through 1Q25 using purchased calls and sold swaps that protect against low gas prices while preserving benefits of higher gas prices
  - ~80% of 2022 swap and collar positions covered by purchased calls
  - Beyond 2022, greater than 95% of swaps are covered by purchased calls

Oil

- ✓ Limited hedging of oil volumes allows W&T to participate in improving oil price environment

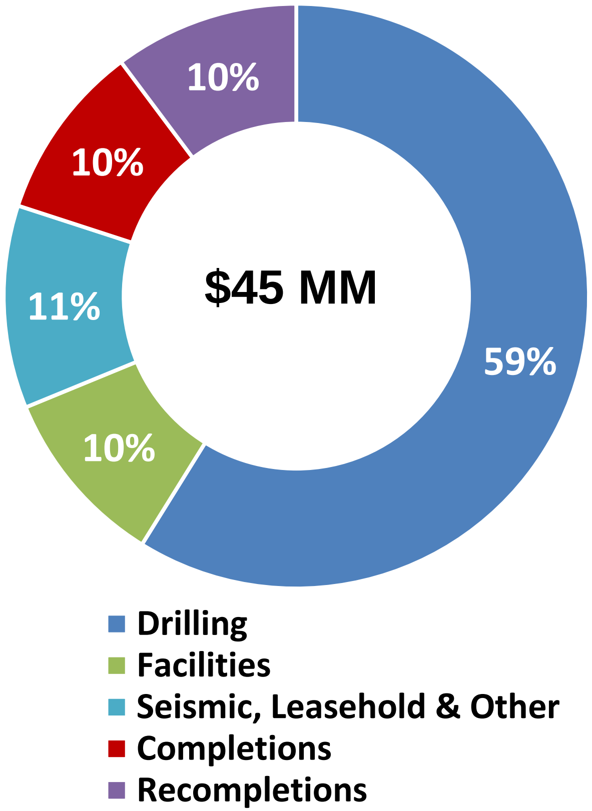
Note: See Appendix for current hedge summary.

2021 Capital Expenditure Budget

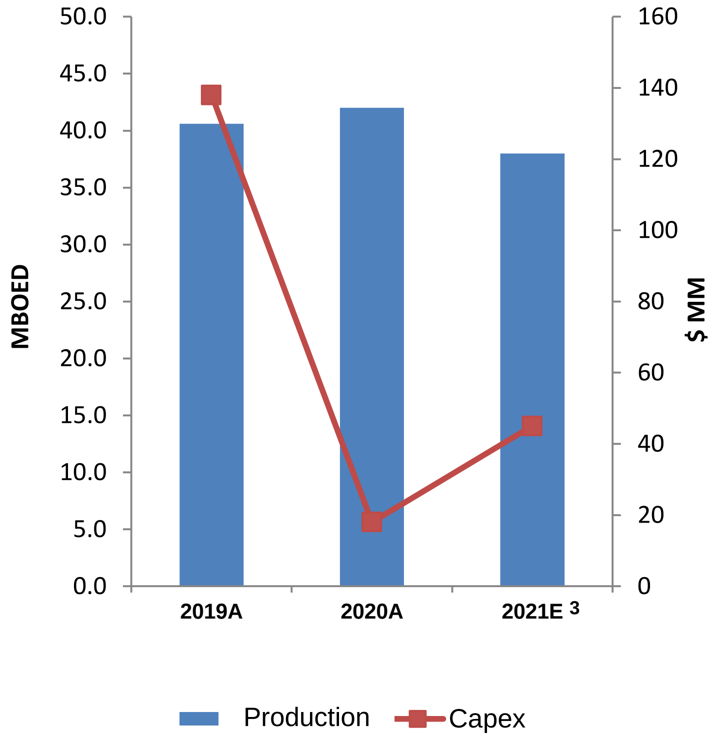
- 2021 CAPEX[1] guidance:
  - $30 - $60 MM
  - 3Q21 YTD actuals - $16.0 MM
  - 2021 spending weighted to 2H21

- 2021 P&A guidance:
  - $25 - $35 MM
    - 2019 actuals - $11.4 MM
    - 2020 actuals - $3.3 MM
    - 3Q21 YTD actuals - $19.7 MM

CAPEX Allocation[1,2]



Production vs Capex



Managing 2021 CAPEX to Enhance Financial Flexibility

1) Accrual basis capital expenditures only.
2) Based on midpoint of 2021 forecast.
3) 2021E is mid-point of annual guidance range.

Well-Positioned for Success

W&T OFFSHORE

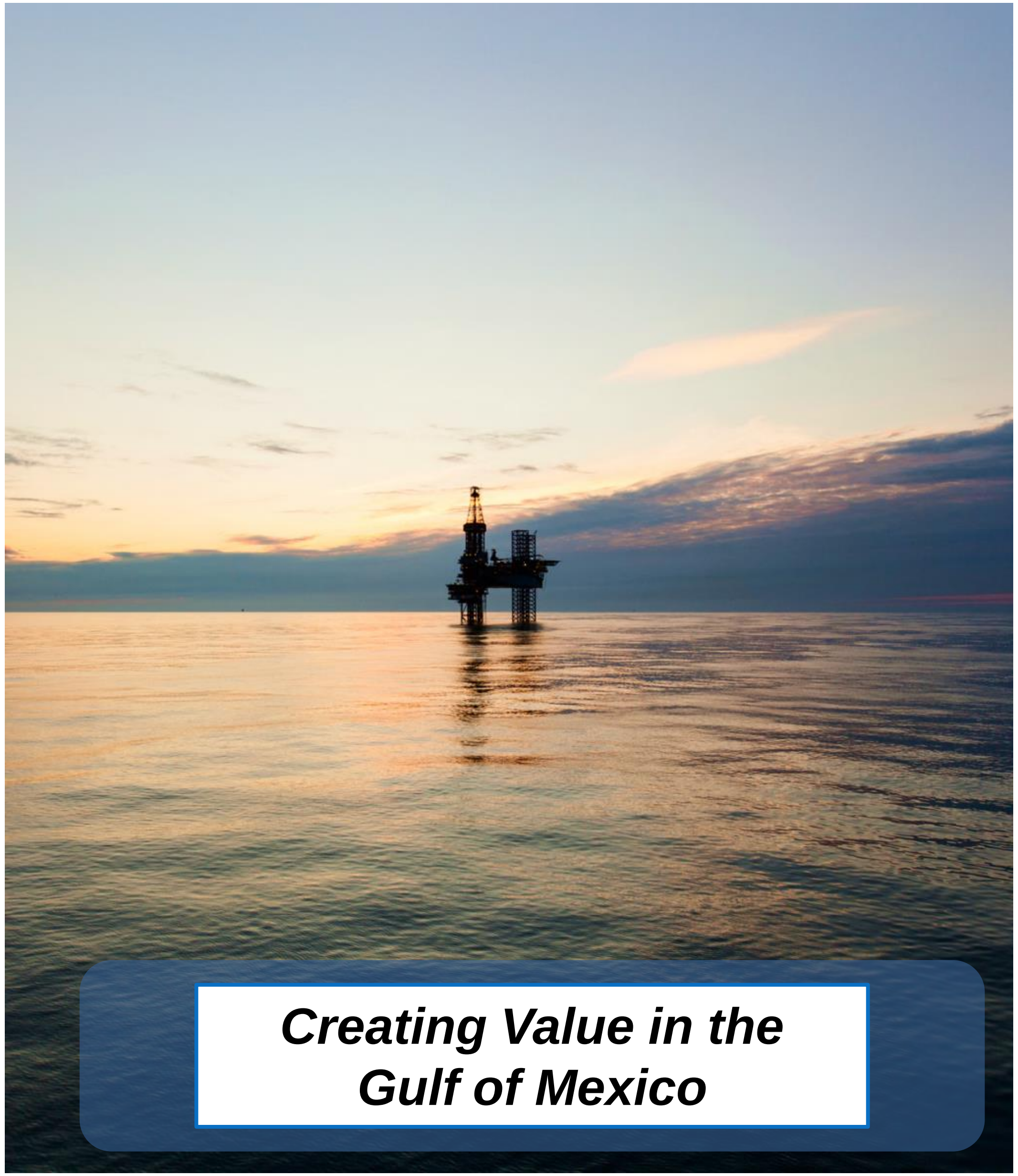
Over 38 Years of Safe Operations in the Gulf of Mexico

Rigorous Technical Evaluation Resulting in High Drilling Success

Proven History of Realizing Probable and Possible Upside

Low Organic F&D Costs Driven by Existing Infrastructure

Operational Cost Cutting Improving Cash Margins



Appendix

Hedge Summary (as of November 30, 2021)

W&T OFFSHORE

W&T (excluding Aquasition, LLC)

Crude Oil - WTI NYMEX

PERIOD	SWAPS			COLLARS			
	Total Volume (Bbl)	Avg daily volume (Bbl/d)	Weighted Avg price per Bbl	Total Volume (Bbl)	Avg daily volume (Bbl/d)	Weighted Avg Floor Price per Bbl	Weighted Avg Ceiling Price per Bbl
4Q21	368,000	4,000	$ 42.06	162,104	1,762	$ 39.55	$ 58.12
1Q22	255,244	2,836	$ 43.45	224,739	2,497	$ 37.98	$ 54.85
2Q22	238,344	2,619	$ 48.20	236,702	2,601	$ 39.85	$ 55.28
3Q22	217,037	2,359	$ 54.53	217,037	2,359	$ 45.00	$ 62.50
4Q22	132,612	1,441	$ 58.38	132,612	1,441	$ 46.00	$ 66.40

Natural Gas - Henry Hub NYMEX

PERIOD	SWAPS			COLLARS			
	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg price per MMBTU	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Avg Floor Price per MMBTU	Weighted Avg Ceiling Price per MMBTU
4Q21	920,000	10,000	$ 2.62	4,610,000	50,109	$ 1.90	$ 3.00
1Q22	1,772,945	19,699	$ 2.77	5,680,000	63,111	$ 1.97	$ 3.49
2Q22	1,296,250	14,245	$ 2.56	4,250,000	46,703	$ 1.89	$ 3.06
3Q22	1,635,191	17,774	$ 2.44	3,680,000	40,000	$ 1.83	$ 3.00
4Q22	1,027,099	11,164	$ 2.60	3,680,000	40,000	$ 1.83	$ 3.00

	PURCHASED CALLS		
	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg price per MMBTU
4Q21	8,020,145	87,175	$ 3.55
1Q22	11,983,668	133,152	$ 4.30
2Q22	10,234,888	112,471	$ 3.80
3Q22	10,437,367	113,450	$ 3.81
4Q22	8,539,740	92,823	$ 3.54
2023	25,550,000	70,000	$ 3.50
2024	23,790,000	65,000	$ 3.50
1Q25	5,580,000	62,000	$ 3.50

Hedge Summary (as of November 30, 2021)

W&T OFFSHORE

Aquasition, LLC

Natural Gas - Henry Hub NYMEX									
PERIOD	SWAPS				PURCHASED PUTS				
	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg price per MMBTU		Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg price per MMBTU	
4Q21	7,500,000	81,522	$	3.06	-	-	$	-
1Q22	7,200,000	80,000	$	3.10	-	-	$	-
2Q22	7,200,000	79,121	$	2.49	-	-	$	-
3Q22	7,200,000	78,261	$	2.52	-	-	$	-
4Q22	7,200,000	78,261	$	2.63	-	-	$	-
1Q23	6,600,000	73,333	$	2.75	-	-	$	-
2Q23	6,600,000	72,527	$	2.30	-	-	$	-
3Q23	6,600,000	71,739	$	2.35	-	-	$	-
4Q23	6,600,000	71,739	$	2.50	-	-	$	-
1Q24	6,000,000	65,934	$	2.68	-	-	$	-
2Q24	6,000,000	65,934	$	2.29	-	-	$	-
3Q24	6,000,000	65,217	$	2.36	-	-	$	-
4Q24	6,000,000	65,217	$	2.51	-	-	$	-
1Q25	5,700,000	63,333	$	2.72	-	-	$	-
2Q25	-	-	$	-	5,700,000	62,637	$	2.19
3Q25	-	-	$	-	5,700,000	61,957	$	2.24
4Q25	-	-	$	-	5,700,000	61,957	$	2.38
1Q26	-	-	$	-	5,100,000	56,667	$	2.55
2Q26	-	-	$	-	5,100,000	56,044	$	2.20
3Q26	-	-	$	-	5,100,000	55,435	$	2.26
4Q26	-	-	$	-	5,100,000	55,435	$	2.39
1Q27	-	-	$	-	4,800,000	53,333	$	2.55
2Q27	-	-	$	-	4,800,000	52,747	$	2.22
3Q27	-	-	$	-	4,800,000	52,174	$	2.28
4Q27	-	-	$	-	4,800,000	52,174	$	2.41
1Q28	-	-	$	-	4,500,000	49,451	$	2.58
2Q28	-	-	$	-	1,500,000	16,484	$	2.25
3Q28	-	-	$	-	-	-	$	-
4Q28	-	-	$	-	-	-	$	-

Rigorous Technical Evaluation Results in Drilling Success

W&T OFFSHORE

Process

1. Leads
2. Screening
3. Technical Evaluation
4. AFE Review
5. Execute

1. Leads high graded for review; once approved, project team assigned and deadlines set
2. Cursory technical evaluation with management and land review with scoping cost and business and technical planning
3. Full technical evaluation with probabilistic risk analysis, AFE costing and economic evaluation
4. Presentation to Executive management for AFE approval
5. Project turned over to execution team and deadlines set

Track Record of Drilling Success

Over 400 leads evaluated since 2011

Success Rate[1]
2011 – 2020
> 90%

50 successful offshore wells drilled since 2011

Rigorous Evaluation Process Has Led to >90% Success Rate Since 2011

1) Includes EC 338/349 Cota well that was drilled in 2020 and is expected to be completed in 2021.

GOM Drilling Joint Venture

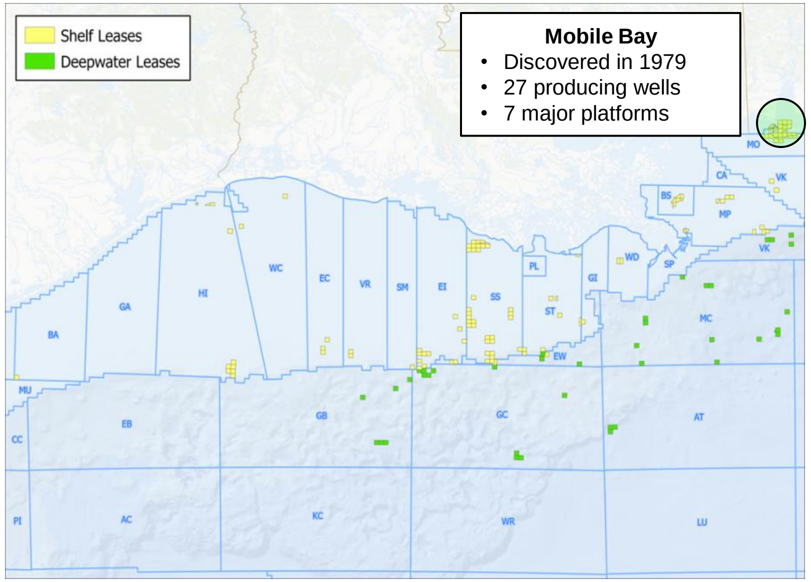
- ✓ Secured $361.4 million commitment for the development of 14 pre-identified drill wells in the GOM with potential to upsize program over time with additional wells
  - Covers the total estimated cost of the 14 wells of $336 million, plus contingency
  - Drilled and completed nine wells through December 31, 2019
  - Successfully drilled one well in 2020 in the East Cameron 338/349 Field (Cota well)
- ✓ W&T initially receives 30% of the net revenues from the drilling program wells for contributing 20% of the capital expenditures plus associated leases and providing access to available infrastructure
- ✓ Upon private investors achieving certain return thresholds, W&T's share of each well's net revenue increases to 38.4%
- ✓ HarbourVest Partners and Baker Hughes/GE are the two largest JV interest owners
- ✓ Leverages BHGE's unique and flexible offering to potentially consolidate engineering, products and services and lower costs
- ✓ Allowed W&T to develop its high return drilling inventory at a faster pace with a greatly reduced capital outlay and maintain flexibility to make acquisitions and pay down debt
- ✓ JV structure expands W&T's access to well capitalized investors

Accelerates Development of High Return Inventory,
Leverages Capital Dollars and Maintains Financial Flexibility

Mobile Bay Acquisition – Key Highlights

- ✓ Acquired ExxonMobil's interests and operatorship in the eastern region of the Gulf of Mexico, offshore Alabama that are adjacent to existing properties owned and operated by W&T as well as related onshore processing facilities
- ✓ Allows for significant synergies, consolidations, and cost savings as W&T is now the largest operator in the area
- ✓ Closed on August 30, 2019, exactly as expected, with total cash consideration paid of $167.6 million which includes a previously-funded $10 million deposit
- ✓ Utilized cash on hand and previously undrawn revolving credit facility to finance acquisition
- ✓ Includes working interests in nine GOM offshore producing fields (eight operated) and onshore gas treatment facility capable of treating 420 MMcf/d
- ✓ Mid-year 2021 net proved reserves of ~82 MMBoe[1] of which the vast majority are proved developed producing (83% natural gas); 2Q'21 avg production 15,331 Boe/d
- ✓ Contains future opportunities including Norphlet drilling leads and optimization of compression facilities
- ✓ Identified potential drilling opportunities that are planned for permitting in 2021 and drilled thereafter
- ✓ ***Completed consolidation of natural gas treating facilities at Mobile Bay, with expected future cost savings of $5 million per year beginning in 2021 and reduction of GHG emissions***

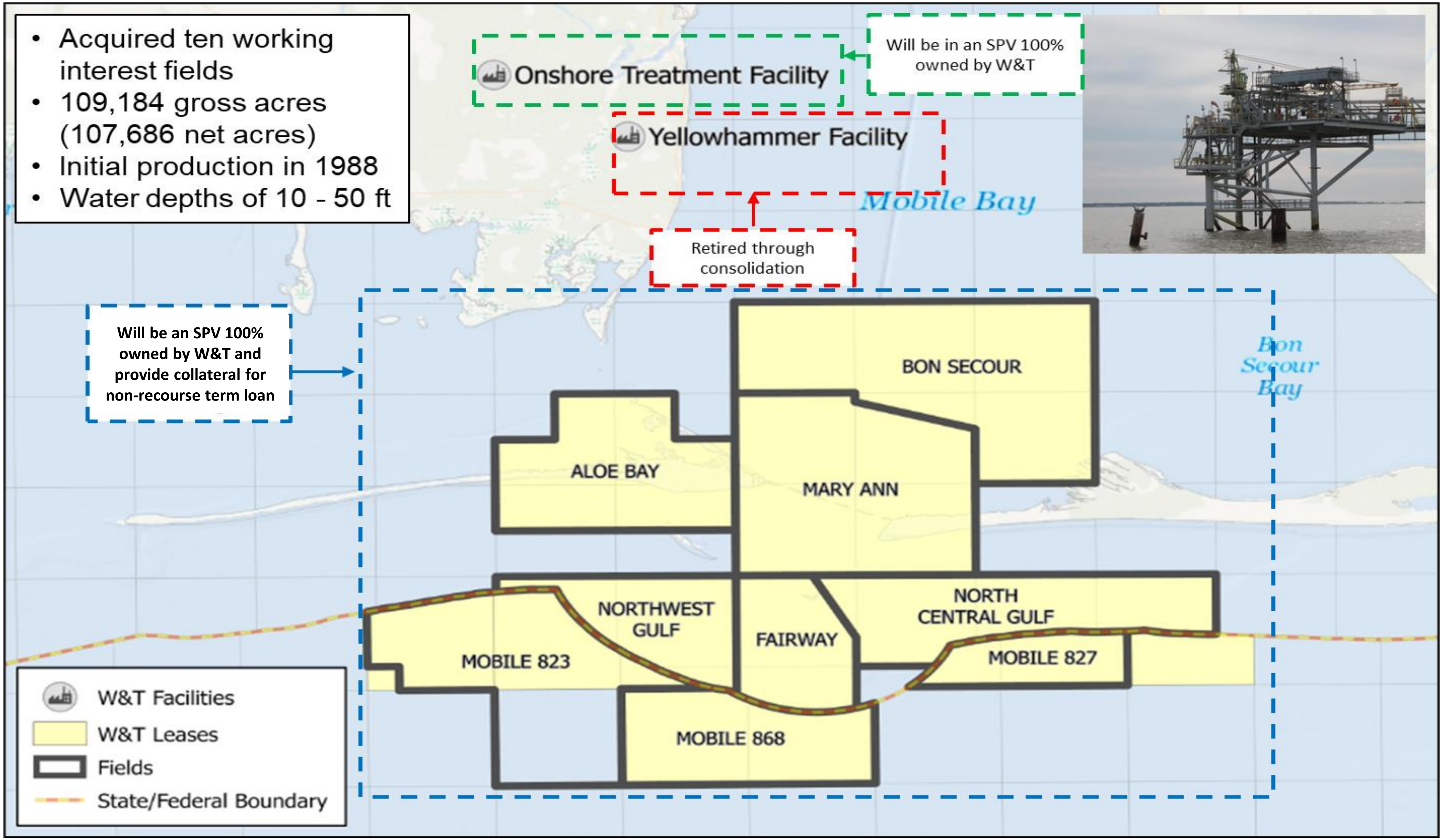
Low Decline, Long-Life, Mostly PDP



1) Based on mid-year-end reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96/MMbtu.

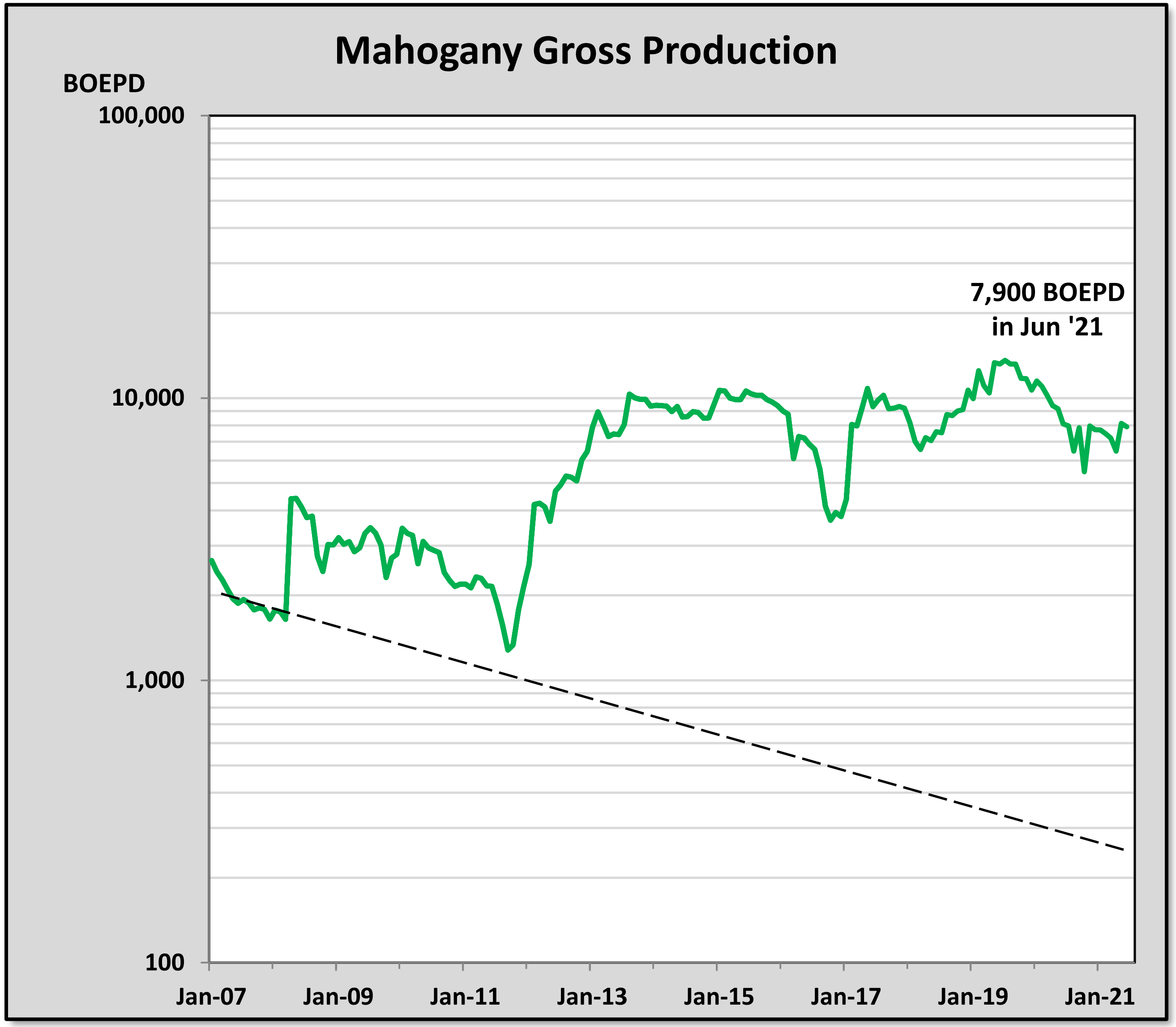
Mobile Bay Area – Asset Map

- Acquired ten working interest fields
- 109,184 gross acres (107,686 net acres)
- Initial production in 1988
- Water depths of 10 - 50 ft



SS 349 Field ("Mahogany") Case Study

W&T OFFSHORE



SS 349 Field ("Mahogany")

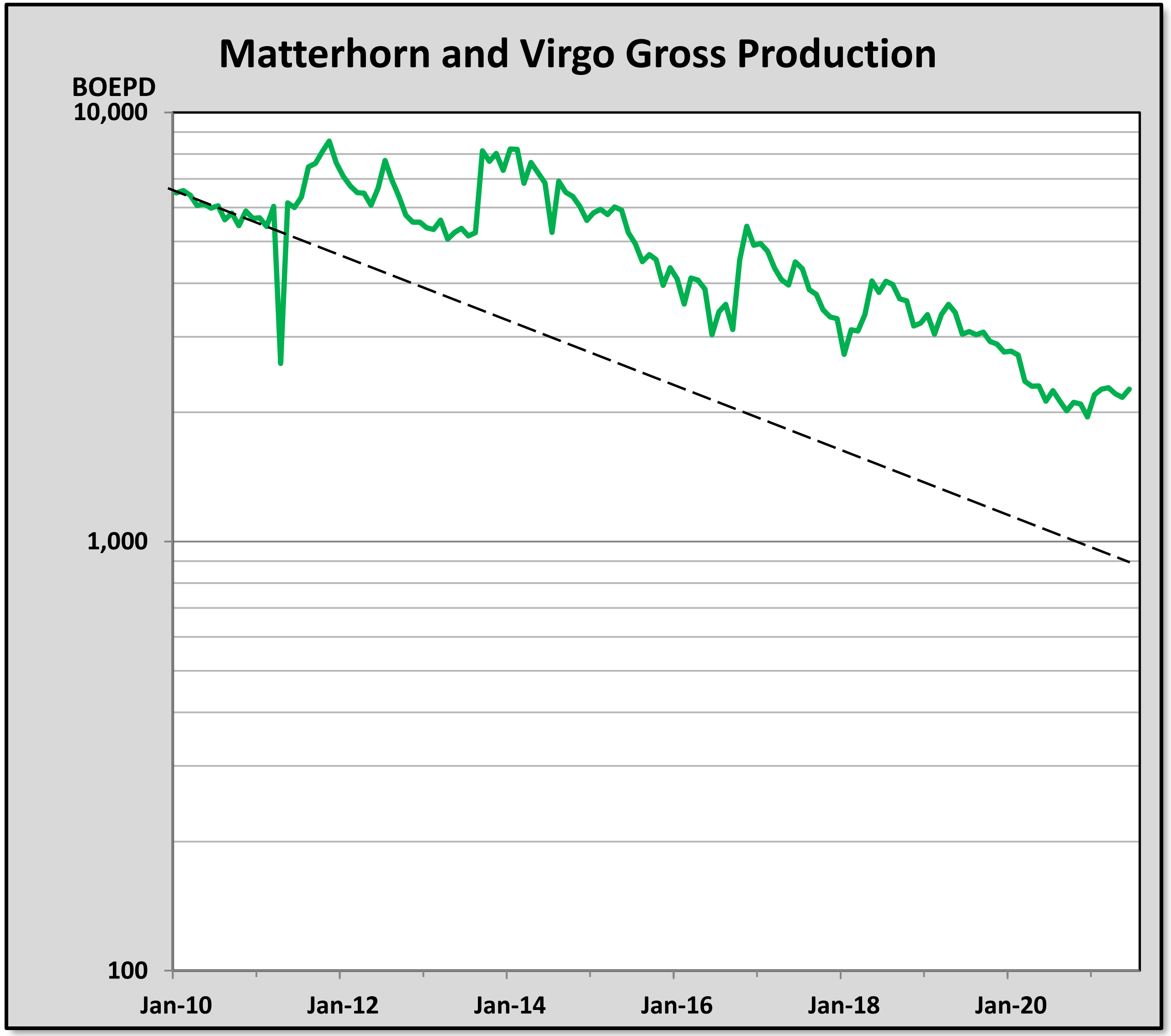
- ✓ WI: 100.0%, 360' Water Depth
- ✓ 1st commercially successful subsalt development in the Gulf of Mexico (initial production in 1997)
- ✓ Purchased interest in 2000, 2004 & 2008
- ✓ Cumulative purchase price of $175MM
- ✓ Valuation
  - Total Net Cash Flow[1] $652MM
  - Mid-year 2P PV10 net of ARO $767MM
  - **Total Project Value[2] $1,419MM**
- ✓ Have increased value by:
  - Development and exploration drilling
  - Performing recompletes
  - Reworks and performance optimization

Current Reserves[3]

1P Reserves:	21.0	MMBoe
2P Reserves:	45.7	MMBoe
3P Reserves:	81.4	MMBoe

1) From final purchase price including capex to June 30, 2021.
2) Total Net Cash Flow as of June 30, 2021, plus Mid-year 2021 2P PV10 value (including ARO).
3) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu.

Total E&P Deepwater Acquisition Case Study



"Matterhorn" & "Virgo" Fields

- ✓ WI: 64% - 100%, 1,130' - 2,400' water depth
- ✓ Purchased from Total E&P, USA in 2010
- ✓ Cumulative purchase price of $115MM
- ✓ Valuation
  - Total Net Cash Flow[1] $503MM
  - Mid-year 2P PV10 net of ARO $134MM
  - **Total Project Value[2] $637MM**
- ✓ Have increased value by:
  - Drilling sidetracks
  - Performing recompletes
  - Instituting waterflood
  - Entering processing arrangement ($69 million in processing revenues received to date)

Current Reserves[3]

1P Reserves:	5.2	MMBoe
2P Reserves:	9.8	MMBoe
3P Reserves:	16.5	MMBoe

1) From final purchase price including capex to June 30, 2021.
2) Total Net Cash Flow as of June 30, 2021, plus Mid-year 2021 2P PV10 (including ARO).
3) Based on mid-year 2021 reserve report at 7/1/2021 average realized NYMEX Strip pricing (1P Life) of $57.80/BO and $2.96MMbtu.

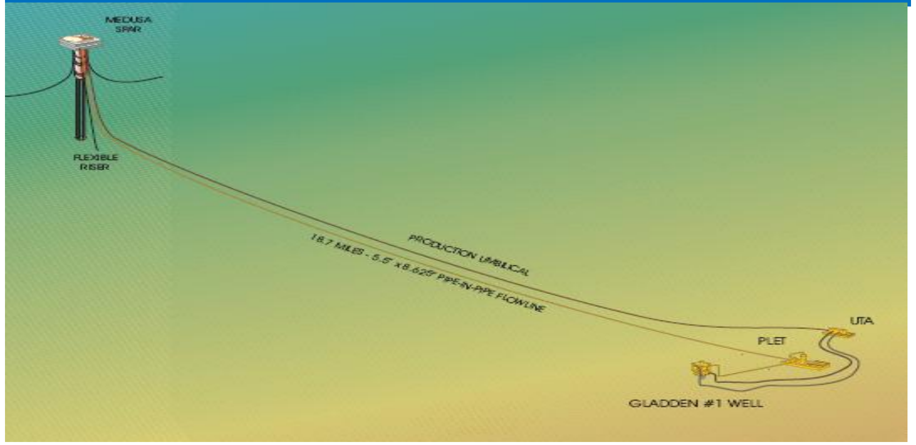
Significant Infrastructure Advantage

W&T OFFSHORE

W&T Owns Infrastructure with an Estimated Replacement Value >$1.0B

Platform Rig on infield production facility (EW 910 Area)

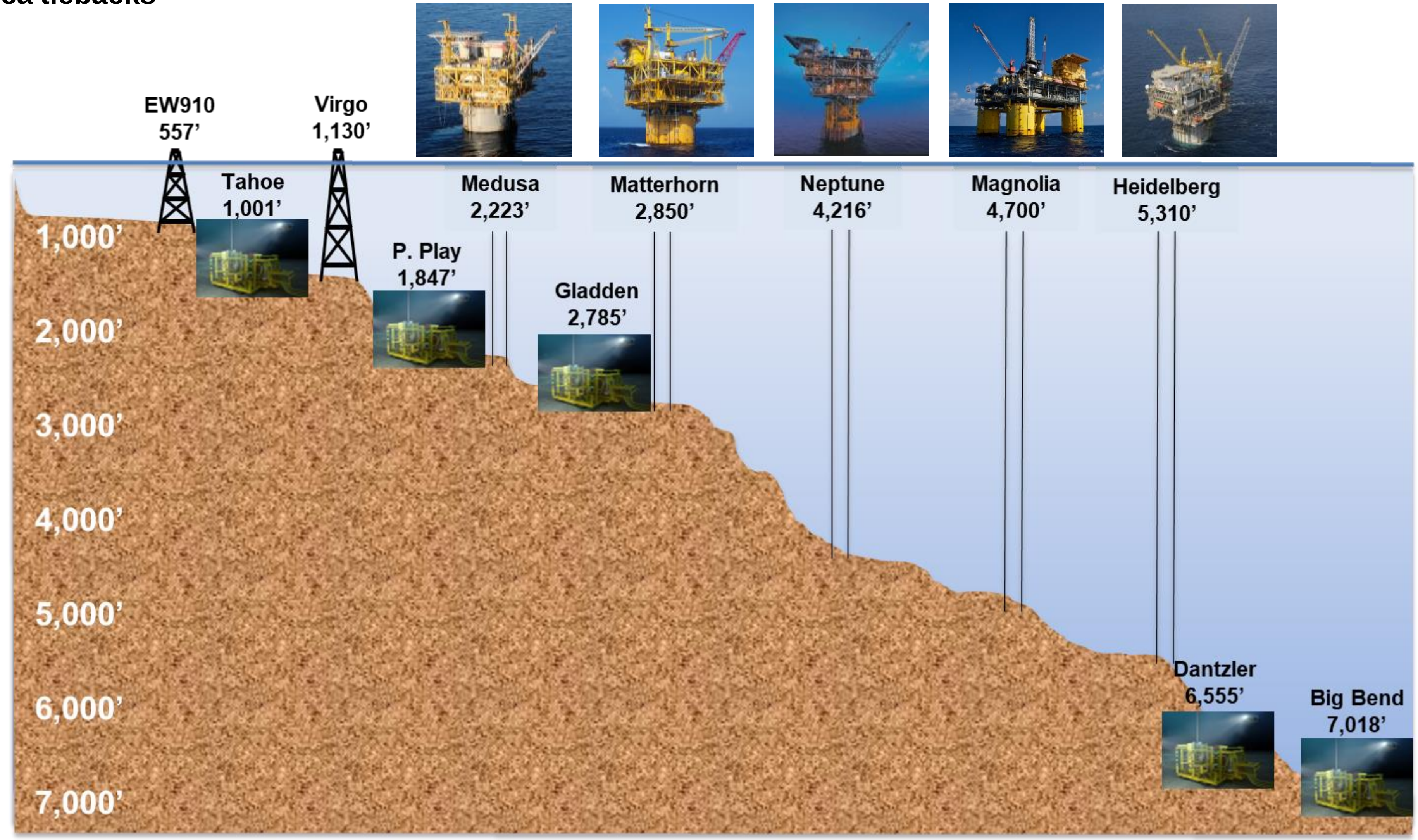
Subsea tieback to existing infrastructure (MC 800 Gladden)



- ✓ **146 existing structures provide a key advantage when evaluating/developing prospect opportunities**
- ✓ **Economic Advantage**
  - *Reduces capital expenditures*
  - *Increases returns by generating cashflow quicker*
  - *Marketing contracts already in place*
  - *Provides revenue upside in potential Production Handling Agreements (PHA)*
    - *2018 $13.4 MM, 2019 $15.3 MM, 2020 $9.1 MM, 1H’21 $6.2 MM*

Successful Diversification in Valuable Deepwater Projects

- ✓ **W&T's deepwater portfolio was expanded and diversified with Magnolia (2019) as its latest addition**
- ✓ **W&T operates and participates in various deepwater production facilities, including TLPs, E-TLPs, SPARs, deepwater fixed structures, and sub-sea tiebacks**



Non-GAAP Reconciliations

Certain financial information included in W&T's financial results are not measures of financial performance recognized by accounting principles generally accepted in the United States, or GAAP. These non-GAAP financial measures are "Adjusted Net (Loss) Income", "Adjusted EBITDA" and "Free Cash Flow". Management uses these non-GAAP financial measures in its analysis of performance. These disclosures may not be viewed as a substitute for results determined in accordance with GAAP and are not necessarily comparable to non-GAAP performance measures which may be reported by other companies.

Reconciliation of Net (Loss) Income to Adjusted Net (Loss) Income

Adjusted Net (Loss) Income does not include the unrealized commodity derivative loss (gain), amortization of derivative premium, bad debt reserve, deferred tax benefit, gain on debt transactions, and litigation and other. Adjusted Net Income is presented because the timing and amount of these items cannot be reasonably estimated and affect the comparability of operating results from period to period, and current periods to prior periods.

	Three Months Ended			Nine Months Ended	
	September 30,	June 30,	September 30,	September 30,	
	2021	2021	2020	2021	2020
	(In thousands, except per share amounts) (Unaudited)				
Net (loss) income	$ (37,964)	(51,672)	(13,339)	$ (90,382)	$ 46,737
Unrealized commodity derivative loss (gain)	43,111	66,083	13,112	125,529	(1,416)
Amortization of derivative premium	805	583	1,483	1,845	9,239
Bad debt reserve	1	8	(1)	9	82
Deferred tax (benefit) expense	(5,820)	(12,802)	(21,170)	(18,826)	(23,407)
Gain on debt transactions	-	-	-	-	(47,469)
Litigation and other	-	40	-	80	-
Adjusted Net Income (Loss)	$ 133	2,240	(19,915)	$ 18,255	$ (16,234)
Basic and diluted adjusted (loss) earnings per common share	$ -	0.02	(0.14)	$ 0.13	$ (0.11)
Weighted Average Shares Outstanding	142,297	142,244	141,624	142,231	141,589

Non-GAAP Reconciliations

Adjusted EBITDA/ Free Cash Flow Reconciliations

The Company also presents the non-GAAP financial measures Adjusted EBITDA and Free Cash Flow. The Company defines Adjusted EBITDA as net (loss) income plus income tax (benefit) expense, net interest expense, and depreciation, depletion, amortization and accretion, excluding the unrealized commodity derivative gain or loss, amortization of derivative premium, bad debt reserve, gain on debt transactions, and litigation and other. Company management believes this presentation is relevant and useful because it helps investors understand W&T's operating performance and makes it easier to compare its results with those of other companies that have different financing, capital and tax structures. Adjusted EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. Adjusted EBITDA, as W&T calculates it, may not be comparable to Adjusted EBITDA measures reported by other companies. In addition, Adjusted EBITDA does not represent funds available for discretionary use.

The Company defines Free Cash Flow as Adjusted EBITDA (defined above), less capital expenditures, plugging and abandonment costs and interest expense (all on an accrual basis). For this purpose, the Company's definition of capital expenditures includes costs incurred related to oil and natural gas properties (such as drilling and infrastructure costs and the lease maintenance costs) and equipment, furniture and fixtures, but excludes acquisition costs of oil and gas properties from third parties that are not included in the Company's capital expenditures guidance provided to investors. Company management believes that Free Cash Flow is an important financial performance measure for use in evaluating the performance and efficiency of its current operating activities after the impact of accrued capital expenditures, plugging and abandonment costs and interest expense and without being impacted by items such as changes associated with working capital, which can vary substantially from one period to another. There is no commonly accepted definition of Free Cash Flow within the industry. Accordingly, Free Cash Flow, as defined and calculated by the Company, may not be comparable to Free Cash Flow or other similarly named non-GAAP measures reported by other companies. While the Company includes interest expense in the calculation of Free Cash Flow, other mandatory debt service requirements of future payments of principal at maturity (if such debt is not refinanced) are excluded from the calculation of Free Cash Flow. These and other non-discretionary expenditures that are not deducted from Free Cash Flow would reduce cash available for other uses.

The following tables present (i) a reconciliation of cash flow from operating activities, a GAAP measure, to Free Cash Flow, as defined by the Company and (ii) a reconciliation of the Company's net (loss) income, a GAAP measure, to Adjusted EBITDA and Free Cash Flow, as such terms are defined by the Company.

Non-GAAP Reconciliations

W&T OFFSHORE

	Three Months Ended			Nine Months Ended	
	September 30,	June 30,	September 30,	September 30,	
	2021	2021	2020	2021	2020
			(In thousands) (Unaudited)		
Net (loss) income	$ (37,964)	(51,672)	(13,339)	$ (90,382)	$ 46,737
Interest expense, net	18,910	16,530	14,135	50,474	46,061
Income tax benefit	(5,902)	(12,740)	(21,057)	(18,846)	(23,294)
Depreciation, depletion, amortization and accretion	26,291	30,952	25,127	83,879	93,736
Unrealized commodity derivative loss (gain)	43,111	66,083	13,112	125,529	(1,416)
Amortization of derivative premium	805	583	1,483	1,845	9,239
Bad debt reserve	1	8	(1)	9	82
Gain on debt transactions	-	-	-	-	(47,469)
Litigation and other	-	40	-	80	-
Adjusted EBITDA	$ 45,252	49,784	19,460	$ 152,588	$ 123,676
Investment in oil and natural gas properties and equipment	(10,169)	(4,281)	1,184	(16,025)	(12,954)
Purchases of furniture, fixtures and other	-	-	-	2	(70)
Asset retirement obligation settlements	(8,531)	(10,251)	(624)	(19,744)	(2,788)
Interest expense, net	(18,910)	(16,530)	(14,135)	(50,474)	(46,061)
Free Cash Flow	$ 7,642	18,722	5,885	$ 66,347	$ 61,803

Non-GAAP Reconciliations

	Three Months Ended			Nine Months Ended	
	September 30, 2021	June 30, 2021	September 30, 2020	September 30, 2021	September 30, 2020
			(In thousands) (Unaudited)		
Net cash provided by operating activities	$ 65,097	$ 1,230	$ 21,260	$ 111,291	$ 114,738
Bad debt reserve	1	8	(1)	9	82
Litigation and other	-	40	-	80	-
Amortization of debt items and other items	(1,128)	(948)	(1,569)	(4,095)	(5,251)
Share-based compensation	(859)	(466)	(1,075)	(1,779)	(3,142)
Current tax benefit (expense) (1)	(82)	62	143	(20)	113
Changes in derivatives receivable (payable) (1)	1,571	21,751	(1,028)	20,140	1,132
Changes in operating assets and liabilities, excluding asset retirement obligation settlements	(46,789)	1,326	(13,029)	(43,256)	(32,845)
Investment in oil and natural gas properties and equipment	(10,169)	(4,281)	1,184	(16,025)	(12,954)
Purchases of furniture, fixtures and other	-	-	-	2	(70)
Free Cash Flow	$ 7,642	$ 18,722	$ 5,885	$ 66,347	$ 61,803

(1) A reconciliation of the adjustment used to calculate Free Cash Flow to the Condensed Consolidated Financial Statements is included below:

Current tax benefit:					
Income tax (benefit) expense	$ (5,902)	$ (12,740)	$ (21,057)	$ (18,846)	$ (23,294)
Less: Deferred income taxes	(5,820)	(12,802)	(21,200)	(18,826)	(23,407)
Current tax benefit (expense)	$ (82)	$ 62	$ 143	$ (20)	$ 113
Changes in derivatives receivable:					
Derivatives receivable (payable), end of period	$ (12,511)	$ (7,289)	$ 1,477	$ (12,511)	$ 1,477
Derivatives receivable (payable), beginning of period	7,289	3,465	(2,505)	282	(345)
Derivative premiums paid	6,793	25,575	-	32,369	-
Change in derivatives receivable (payable)	$ 1,571	$ 21,751	$ (1,028)	$ 20,140	$ 1,132

Non-GAAP Reconciliations

We refer to PV-10 as the present value of estimated future net revenues of proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs and excludes ARO. We have also included PV-10 after ARO below. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate and no inflation of current costs. Neither PV-10 nor PV-10 after ARO are financial measures defined under GAAP; therefore, the following table reconciles these amounts to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the non-GAAP financial measures of PV-10 and PV-10 after ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 after ARO are used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. We believe the use of pre-tax measures is valuable because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid. Management believes that the presentation of PV-10 and PV-10 after ARO provide useful information to investors because they are widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 and PV-10 after ARO are not measures of financial or operating performance under GAAP, nor are they intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 after ARO should not be considered in isolation or as substitutes for the standardized measure of discounted future net cash flows as defined under GAAP. Investors should not assume that PV-10, or PV-10 after ARO, from our proved oil and natural gas reserves shown above represent a current market value of our estimated oil and natural gas reserves.

The reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves is as follows (in millions):

		December 31, 2020
Present value of estimated future net revenues (PV-10)[1] ……	$	740.9
Present value of estimated ARO, discounted at 10% ……	$	(204.2)
PV-10 after ARO ……	$	536.7
Future income taxes, discounted at 10% ……	$	(43.0)
Standardized measure of discounted future net cash flows[2] ……	$	493.7

		June 30, 2021
Present value of estimated future net revenues (PV-10)[3] ……	$	1,030.5
Present value of estimated ARO, discounted at 10% ……	$	(205.0)
PV-10 after ARO ……	$	825.5

1) Based on year-end 2020 reserve report by NSAI at average realized SEC pricing of $37.78/BO and $2.05/MMbtu.
2) Company calculates Standardized measure of discounted future net cash flows annually for Form 10-K filing.
3) Based on mid-end 2021 reserve report by NSAI at average realized SEC pricing of $47.78/BO and $2.50MMbtu.

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