W&T OFFSHORE

Four Decades of Industry Leadership in the Gulf of Mexico

34th Annual Roth Conference

March 14, 2022

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, 2021 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.

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

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

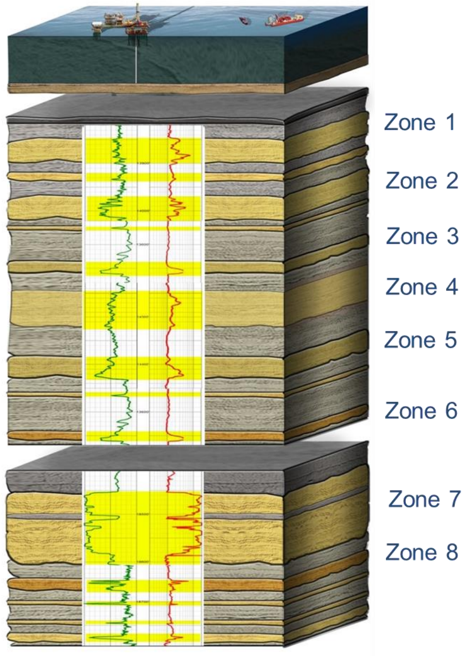
GOM Provides Better Porosity and Permeability than the Unconventionals

Multiple stacked pay opportunities

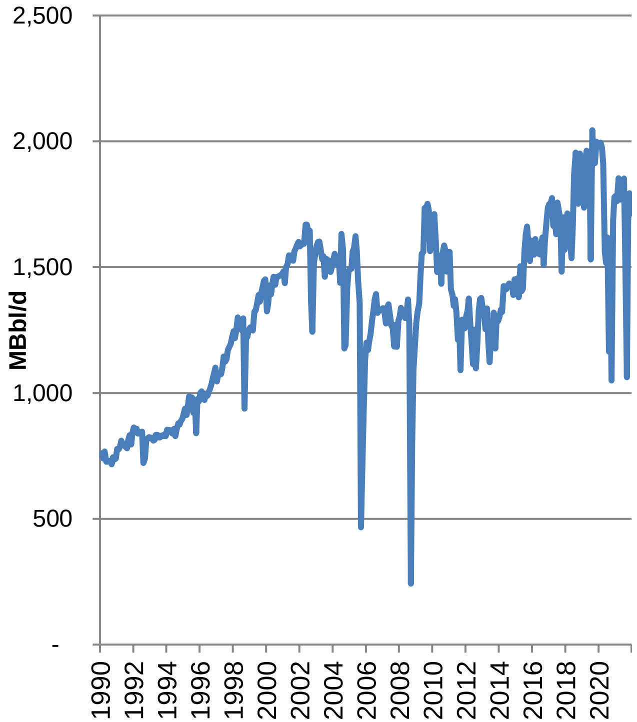
- Offer attractive primary production and recompletion opportunities
- Provide multiple targets improving chance of success when drilling

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

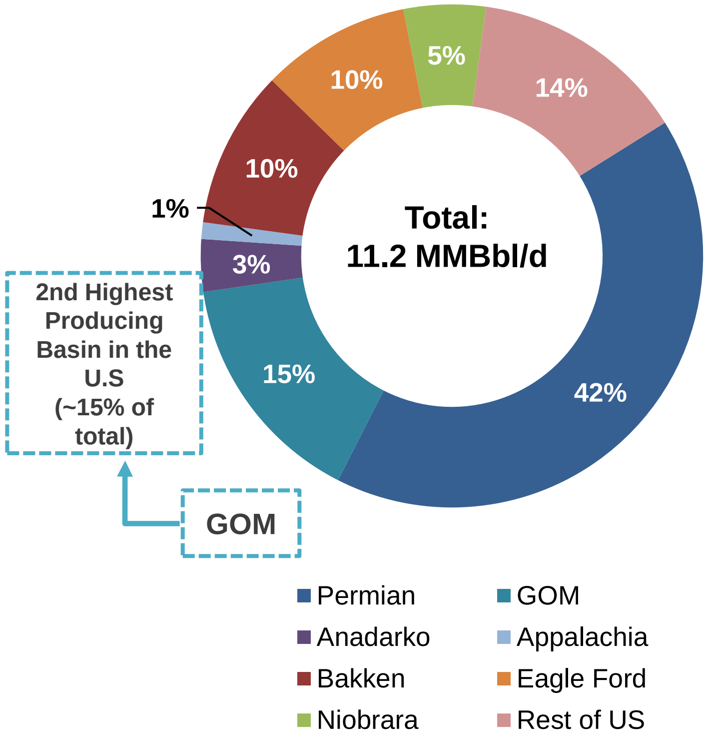
- High quality sandstones have drive mechanisms superior to depletion drive alone
- Enjoy incremental reserve adds, partly due to how reserve quantities are booked or categorized under SEC guidelines



GOM Historical Oil Production[1]



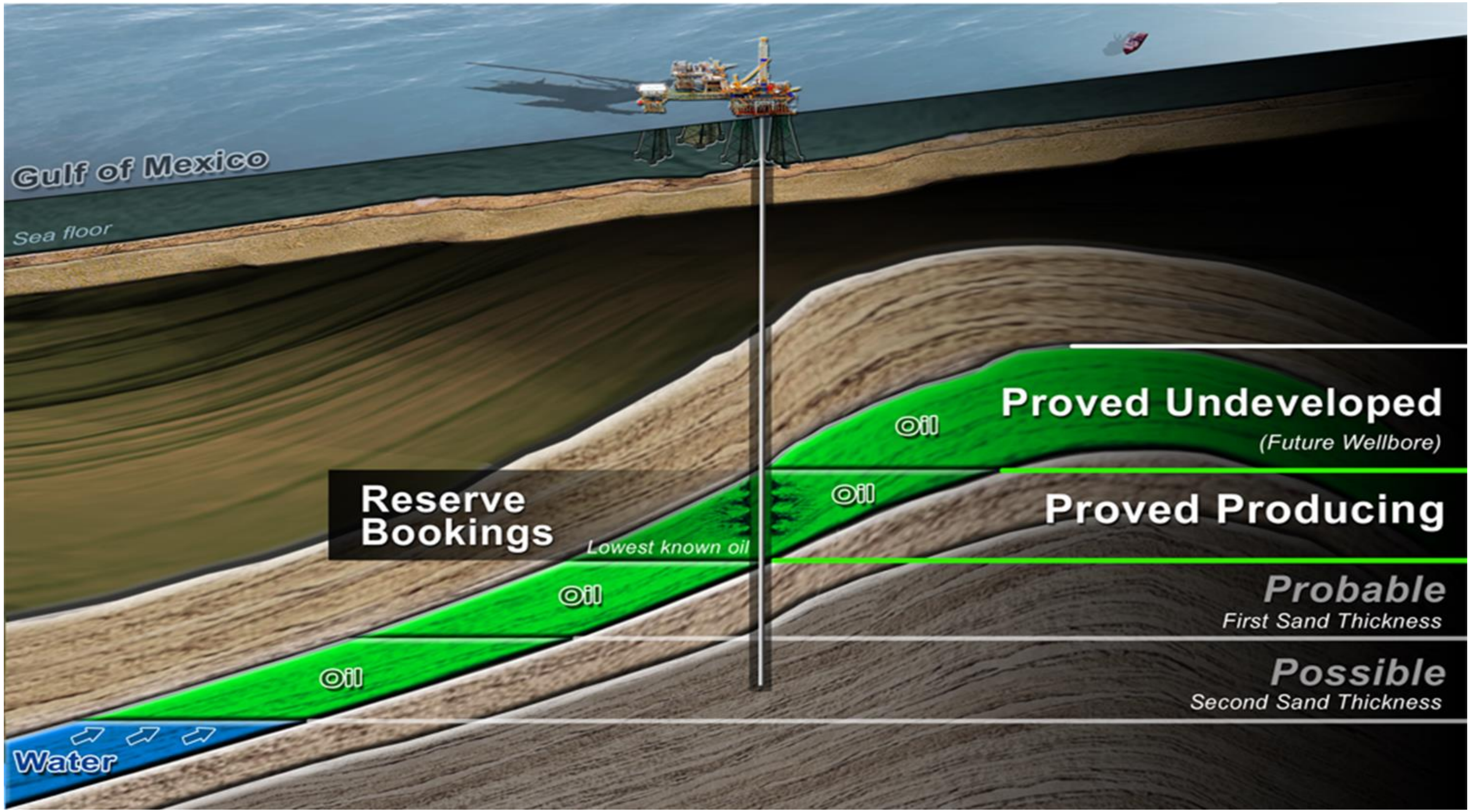
US Oil Production by Key Region[2]



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 February 2022.
2) Based on U.S. Energy Information Administration (EIA) for the year-ended 2021.

Incremental Reserves May Be Produced at No Cost



Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

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

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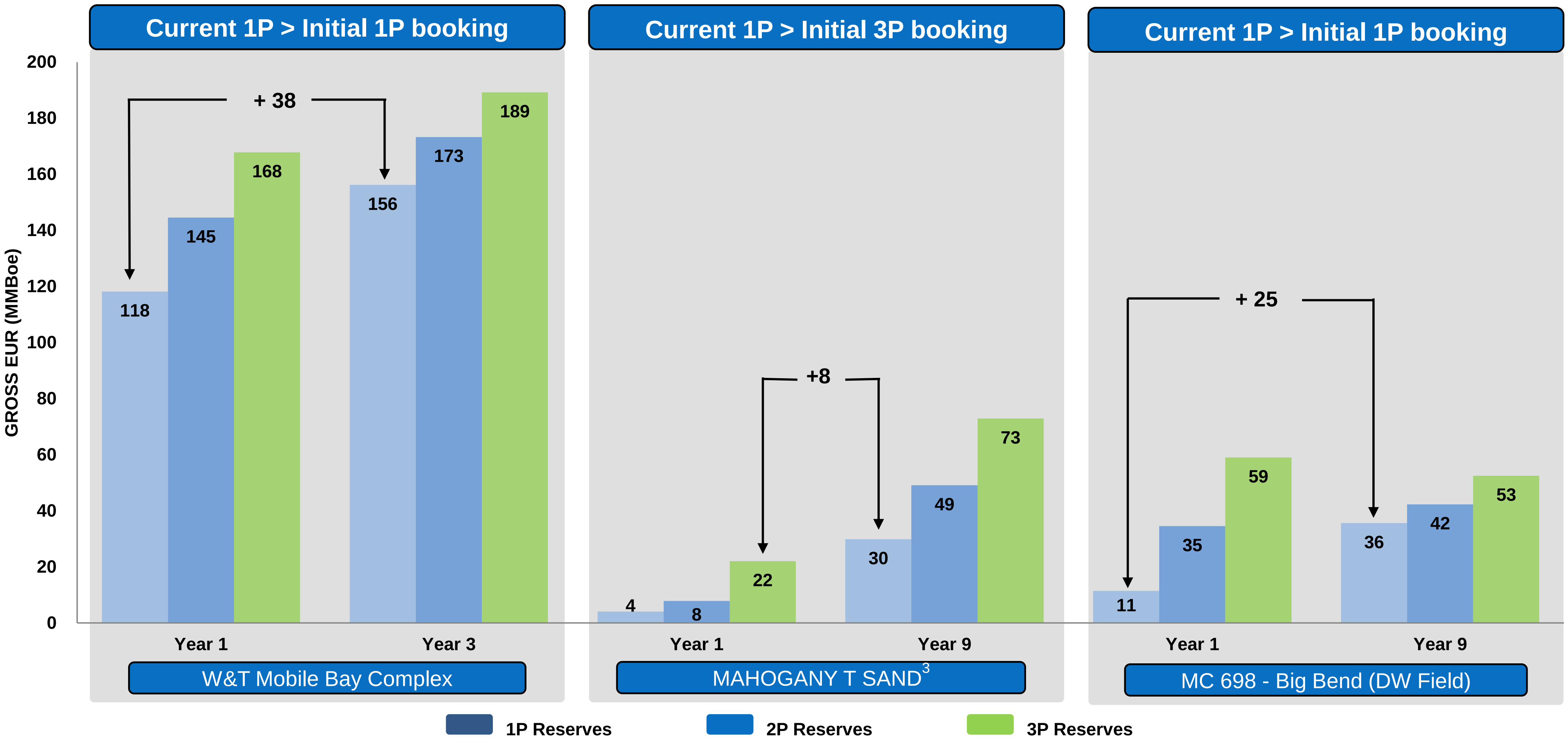

1) Based on year-end 2021 reserve report at 12/31/21 by NSAI at 3/02/22 average realized NYMEX Strip pricing (1P Life) of $73.65/BO and $3.83/MMBtu.
2) 1P = Proved, 2P = Proved + Probable, 3P = Proved + Probable + Possible.
3) Initial 1P booking includes A-14 well only; Mid-Year 2021 1P booking includes A-14, A-18 and A-19 wells; 2P & 3P includes additional development wells.

Realizing Incremental Reserve Upside[1]

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

1 Prob + Poss Related to PDP

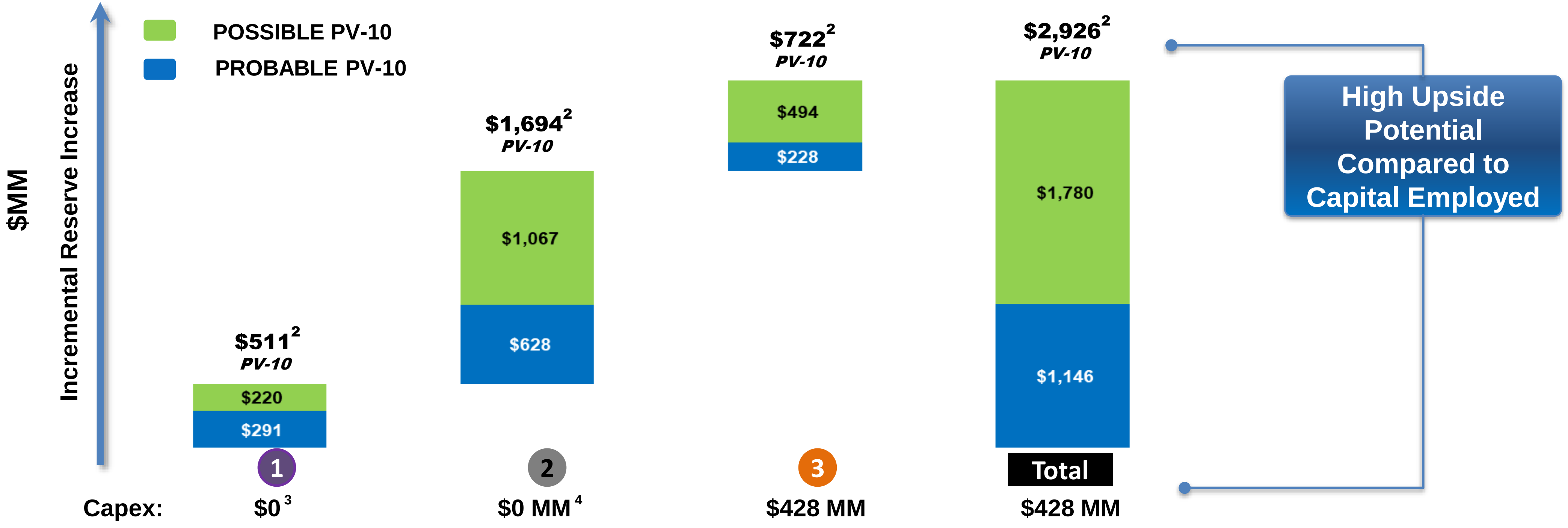
- No additional capex required
- Achievable because of WTI's demonstrated understanding of the fields

2 Prob + Poss Related to PDNP + PUD

- Contingent on execution of field development plans
- De minimis 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 year-end 2021 reserve report using strip pricing as of 3/02/22 NYMEX pricing (1P Life) of $73.65/BO and $3.83/MMbtu.
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.

Leveraging Four Decades of GOM Acquisition Expertise

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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 717 Boe/d from Matterhorn and Virgo

Reserves [(2)]:	**1P –**	**5.5 MMBoe**
	2P –	**10.8 MMBoe**
	3P –	**17.7 MMBoe**

Shell

$116MM
Paid out in Nov. 2012

Net average production[(1)] of 558 Boe/d from Tahoe and 6 other fields

Reserves [(2)]:	**1P –**	**1.0 MMBoe**
	2P –	**1.7 MMBoe**
	3P –	**2.2 MMBoe**

NEWFIELD

$206MM
Paid out in Nov. 2014

Net average production[(1)] of 159 Boe/d from 78 offshore blocks, 65 of which are in deepwater

Reserves [(2)]:	**1P –**	**1.6 MMBoe**
	2P –	**4.9 MMBoe**
	3P –	**9.3 MMBoe**

Shell / Marubeni

$61MM
Paid out in Oct. 2014

Net average production[(1)] of 2,798 Boe/d from Fairway Field

Reserves [(2)]:	**1P –**	**14.5 MMBoe**
	2P –	**15.7 MMBoe**
	3P –	**16.8 MMBoe**

woodside

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

Net average production[(1)] of 815 Boe/d from Neptune and 24 add'l blocks. One exploration well brought on production in 2014

Reserves [(2)]:	**1P –**	**1.9 MMBoe**
	2P –	**2.1 MMBoe**
	3P –	**2.5 MMBoe**

CALLON PETROLEUM

$83MM
Investments Post Acquisition

Net average production[(1)] of 155 Boe/d from Medusa and 12 other fields

Two exploration wells brought on production in June 2015

Reserves [(2)]:	**1P –**	**2.1 MMBoe**
	2P –	**4.0 MMBoe**
	3P –	**6.5 MMBoe**

Cobalt International Energy

$17MM
Paid out in Aug. 2018

Net average production[(1)] of 377 Boe/d from Green Canyon 859, 903, & 904

Reserves [(2)]:	**1P –**	**0.2 MMBoe**
	2P –	**0.3 MMBoe**
	3P –	**0.4 MMBoe**

ExxonMobil

$168MM
Closed August 30, 2019

Net average production[(1)] of 14,9521 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 –**	**78.7 MMBoe**
	2P –	**89.1 MMBoe**
	3P –	**99.0 MMBoe**

ConocoPhillips / Marubeni

$18MM
Paid out in Apr. 2021

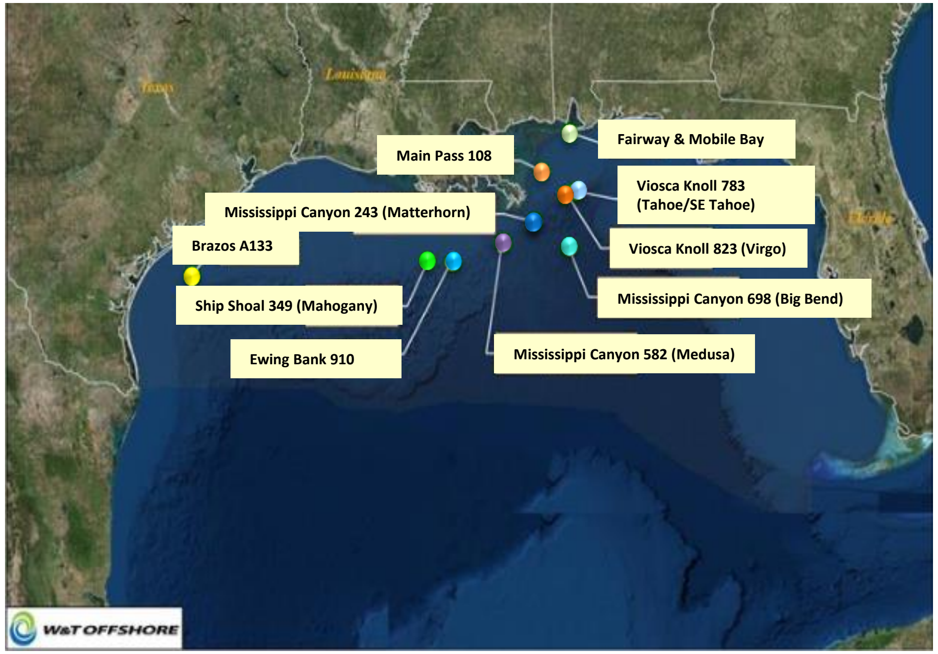
Net average production[(1)] of 2,095 Boe/d from Garden Banks 783 & 784 (Magnolia Field)

Reserves [(2)]:	**1P –**	**11.8 MMBoe**
	2P –	**21.3 MMBoe**
	3P –	**40.7 MMBoe**

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

1) Reflects 4Q21 net average production.
2) Based on year-end 2021 reserve report at 12/31/21 by NSAI at 3/02/22 average realized NYMEX Strip pricing (1P Life) of $73.65/BO and $3.83/MMBtu.

Company Snapshot

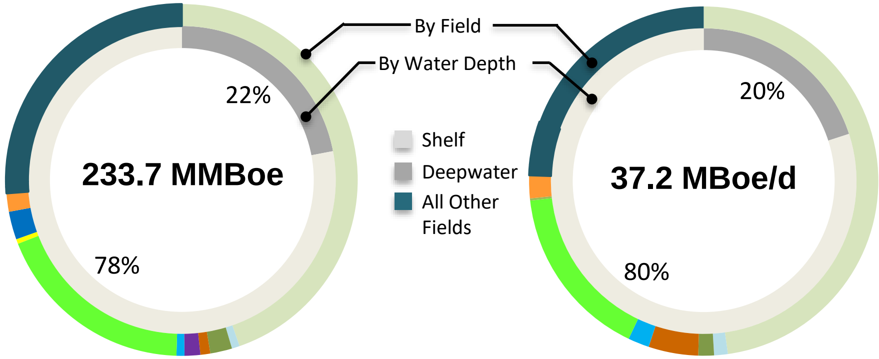


4Q21 Average Production:	37.2 MBoe/d (45% liquids)
Total Fields	47
2021 Adjusted EBITDA[1]	$220.3 MM
2021 Free Cash Flow[1]	$90.9 MM

Net Year-End Reserves (MMBoe)	SEC Pricing[3]	NYMEX Strip[4]
1P	157.6	159.5
2P	233.7	236.2
3P	341.5	343.6

2P Reserves Mix[2,3]

4Q21 Avg. Daily Production[2]



Gulf of Mexico Shelf

- ~482,000 gross acres (~381,000 net)
- 80% of 4Q21 production of 37.2 MBoe/d
- Proved reserves of 130.8 MMBoe[3]
- 2P reserves of 183.1 MMBoe[3]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

- ~187,000 gross acres (~77,000 net)
- 20% of 4Q21 production of 37.2 MBoe/d
- Proved reserves of 26.8 MMBoe[3]
- 2P reserves of 50.6 MMBoe[3]
- Substantial upside with existing acreage

Federal vs State

- Production: Federal 57%, State 43%
- Net Acreage: Federal 79%, State 21%

Premier GOM Operator with Four Decades 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 year-end 2021 reserve report by NSAI at average realized SEC pricing (1P Life) of $66.55/BO and $3.60/MMbtu.
4) Based on year-end 2021 reserve report at 3/02/22 average realized NYMEX Strip pricing (1P Life) of $73.65/BO and $3.83/MMbtu.

Recent Highlights

4Q21 Production

- Produced **37.2 MBoe/d**, or 3.4 MMBoe (45% liquids) in 4Q21

2021 Free Cash Flow[1]

- Produced Free Cash Flow of **$90.9** million in 2021

2021 Adjusted EBITDA[1]

- Generated Adjusted EBITDA of **$220.3** million in 2021

✓ Completed opportunistic ANKOR acquisition in February of 2022, adding low-risk cash-flowing assets with identified upside potential without significant capital expenditures

✓ **Net Debt down $202.0 million, or 29%, from year-ended December 31, 2019 to December 31, 2021, despite Covid-19, negative oil prices, and hurricane impacts**

✓ Enhanced capital structure and liquidity 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 9% to 157.6 MMBoe[3] at year-over-year, representing a reserve replacement ratio of nearly 195% of production for 2021**

- PV-10 of SEC year-end 2021 proved reserves increased 119% to $1.6 billion[2,3]
- **PV-10 of 2021 year-end proved reserves at 3/02/22 strip pricing is $2.0 billion[2,4]**

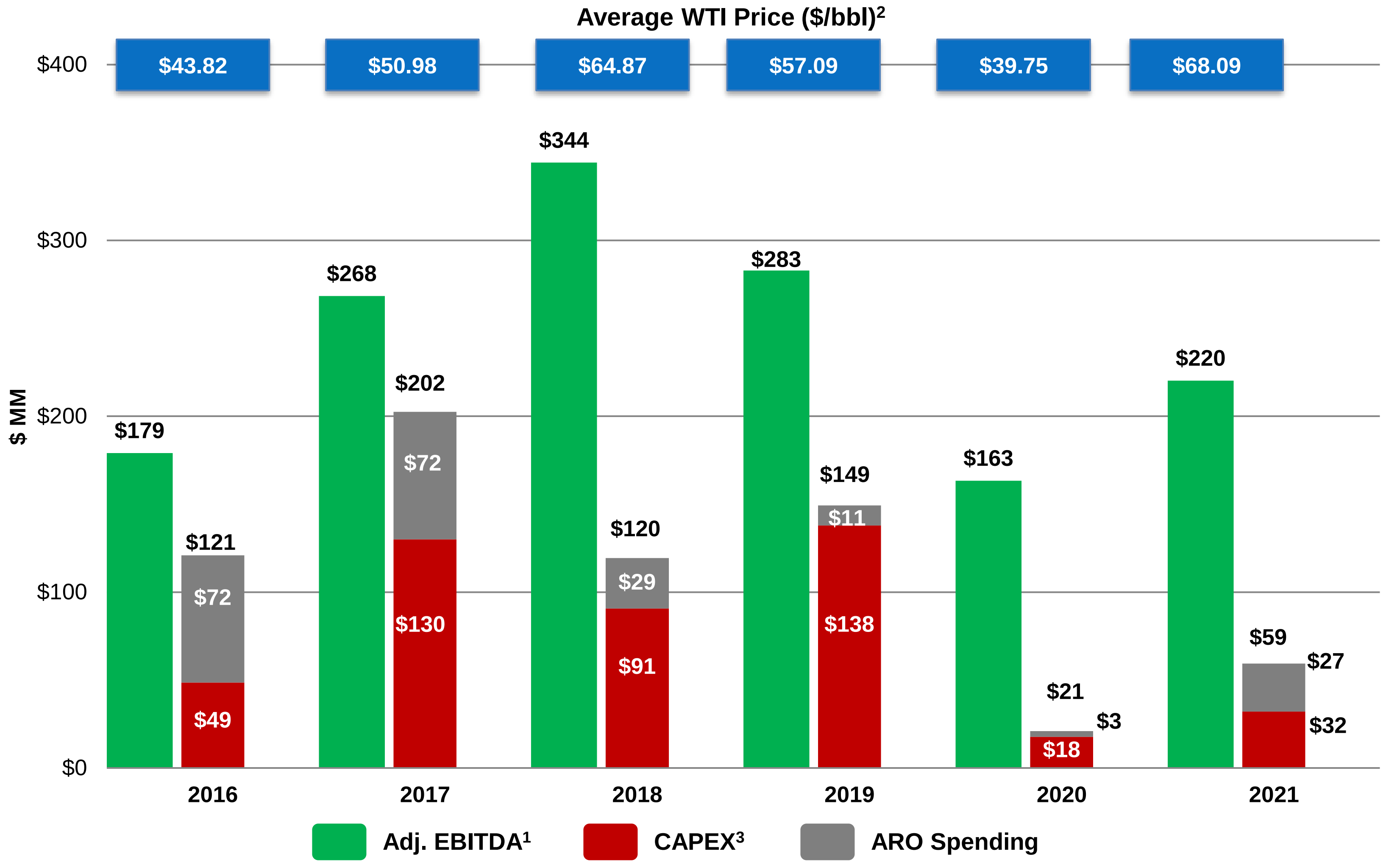
✓ Continued focus on Environmental, Social and Governance ("ESG") initiatives

- 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

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 year-end 2021 reserve report by NSAI at average realized SEC pricing (1P Life) of $66.55/BO and $3.60/MMbtu.
4) Based on year-end 2021 reserve report at 3/02/22 average realized NYMEX Strip pricing (1P Life) of $73.65/BO and $3.83/MMbtu.

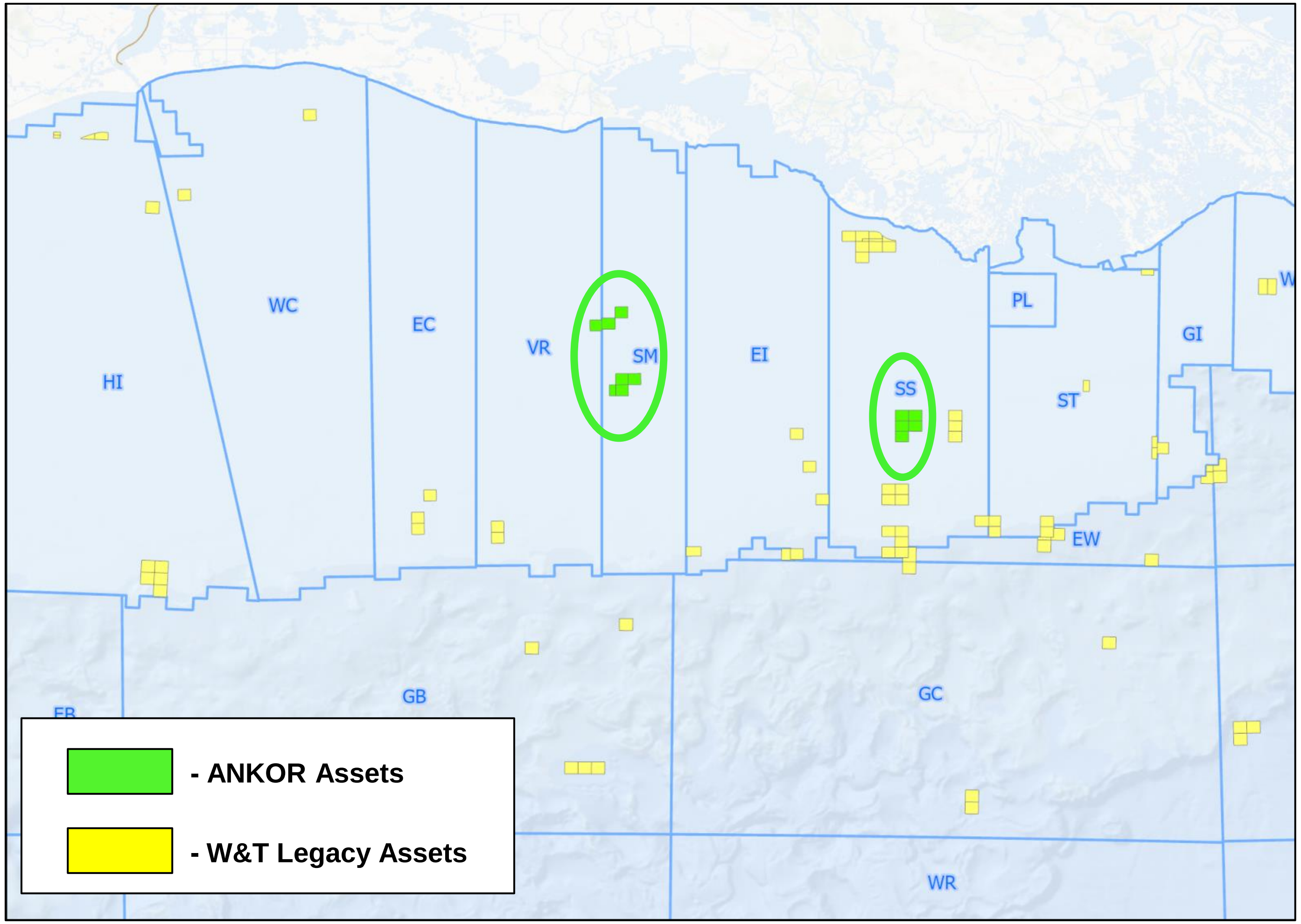
Generating Significant Free Cash Flow[1]



- ✓ Strong production base and cost optimization delivers steady Adjusted EBITDA[1]
- ✓ **Adjusted EBITDA[1] has materially outpaced CAPEX and ARO spending (before 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
- ✓ **In 2021, reduced net debt by ~$97 MM**

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.

ANKOR Acquisition



- ✓ Closed on ANKOR acquisition on February 1, 2022, which added over 50 gross producing wells (avg. WI of 80%)
- ✓ W&T acquired operated, shallow water assets at:
  - Ship Shoal 230
  - South Marsh Island 27/Vermilion 191
  - South Marsh Island 73
- ✓ Purchase price of ~$47 million (~$30 million after post-effective date adjustments for July 1, 2021 effective date) funded with cash on hand
- ✓ Adds internally-estimated proved reserves of 5.5 MMBoe[1] (69% oil) and 7.6 MMBoe[1] (75% oil) of 2P reserves
- ✓ Upside potential through recompletions and operational synergies

Accretive Acquisition in Core GoM with Upside Potential

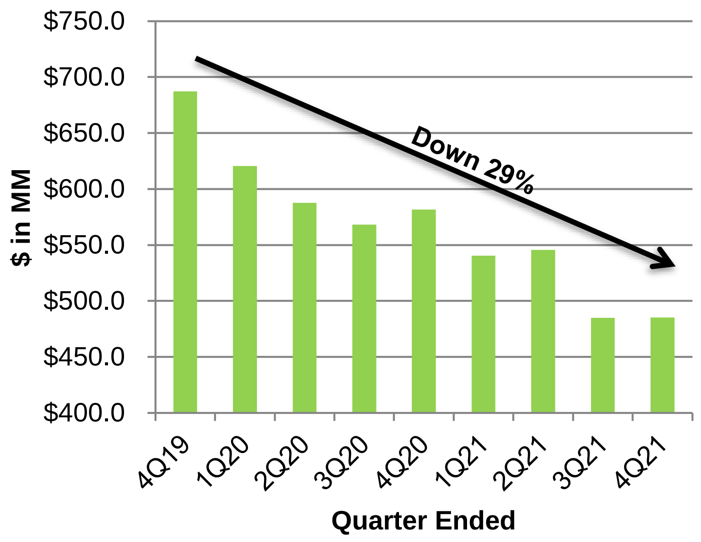
1) Reserves estimated as of July 1, 2021 assuming December 7, 2021 strip pricing

Capital Structure as of December 31, 2021

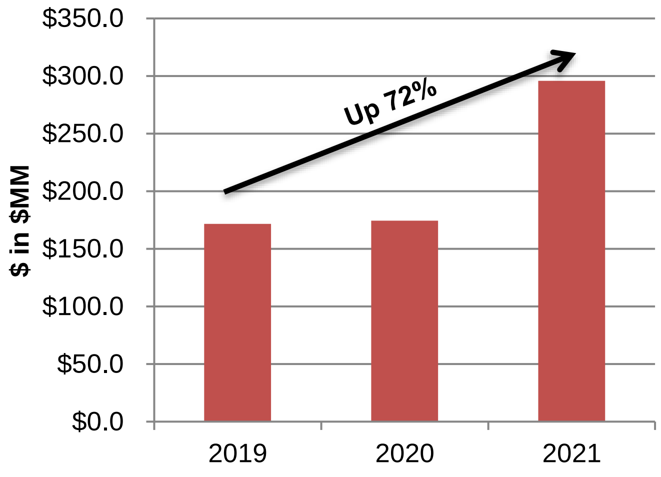
Net Debt[1] as of 12/31/21 ($ in millions)

Total Cash & Equivalents	**$245.8**
9.75% 2nd Lien Notes due Nov. 2023	$547.6
RBL Borrowings	-
7% Non-recourse Term Loan due 2028	$183.3
Total Debt	**$730.9**
Net Debt[1]	**$485.1**

Net Debt[1] Over Time



Year-end Liquidity[2]



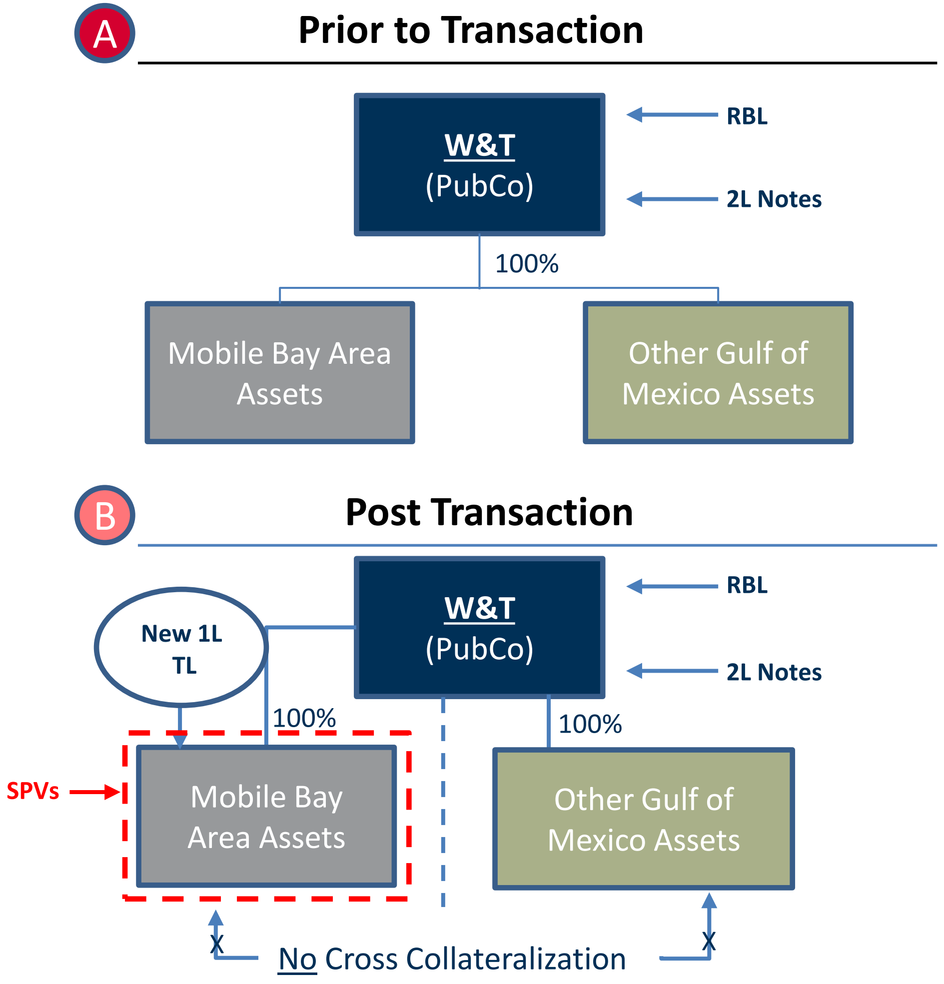
- ✓ Proven track record of generating free cash flow and prudently managing the balance sheet through multiple price environments
- ✓ Despite a difficult couple of years with COVID-19, negative oil prices, and hurricane impacts, **W&T reduced net debt by $202.0 MM** from December 31, 2019 to December 31, 2021
- ✓ Recent Mobile Bay transaction **enhanced liquidity and 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) Liquidity is defined as cash and cash equivalents plus availability under RBL or credit facility.

Munich Re Transaction Overview

- ✓ Partnered with Munich Re, a reputable AA-rated counter-party, to fund future growth needs
- ✓ 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

Exxon/Chevron Mobile Bay Case Study

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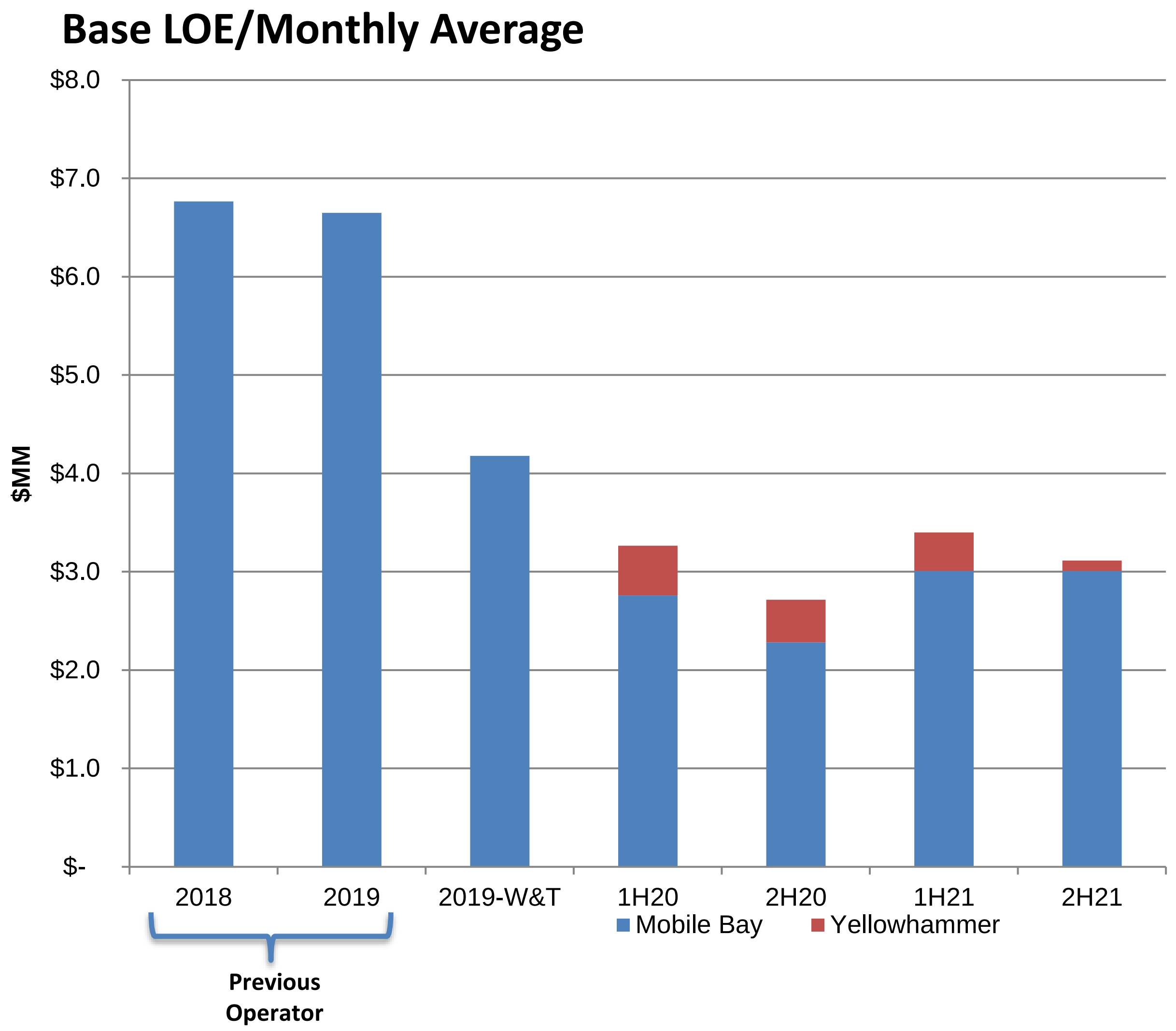


"XOM/CVX Mobile Bay" Fields

- WI: 25% - 100%, 10' - 50' water depth
- Purchased in 2019/2020
- $171 MM acquisition cost
- Valuation
  - Total Net Cash Flow[1] $136 MM
  - Year-end 2P PV10[2] net of ARO $607 MM
  - **Total Project Value[3] $743 MM**
- Have increased value by:
  - Consolidation of treatment facilities in the area
  - Modify treatment of waste oil
  - Reducing downtime

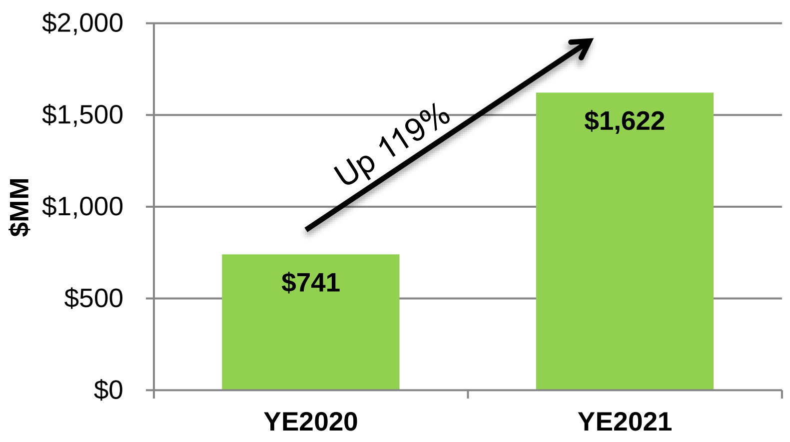
Current Reserves[3]

1P Reserves:	78.7	MMBoe
2P Reserves:	89.1	MMBoe
3P Reserves:	99.0	MMBoe

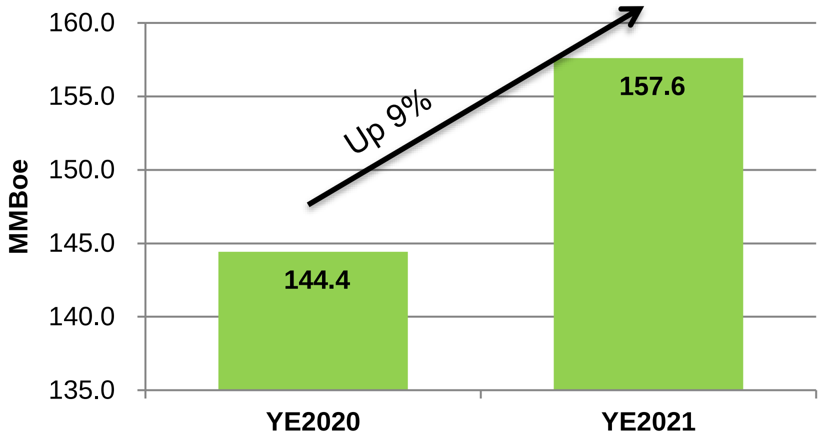
1) From closing date including capex to December 31, 2021.
2) Based on year-end 2021 reserve report strip pricing as of 3/02/22 NYMEX (1P Life) of $73.65/BO and $3.83/MMbtu.
3) Total Net Cash Flow as of December 31, 2021 plus year-end 2021 2P PV10 (including ARO).

Significant Increase in Year-end Reserves and PV-10

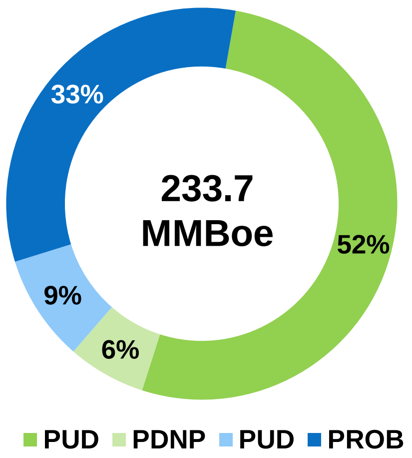
Proved Reserve PV-10[1,2]



Proved Reserves[1,2]

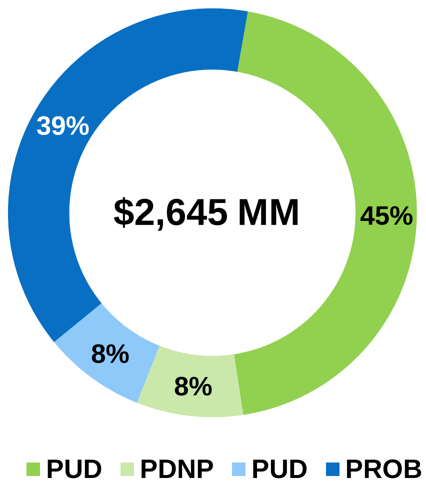


2P SEC Reserves[1]



Natural Gas 57.9% Liquids 42.1%

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



Reserve Category	Oil (MMBoe)	NGL (MMBoe)	Gas (Bcf)	Total (MMBoe)	% Liquids	Pre-Tax PV-10[2] ($MM)
Proved Developed Producing (PDP)	20.8	16.4	507.9	121.9	30.6%	$1,185.2
Proved Developed Non-Producing (PDNP)	6.8	1.4	41.3	15.1	54.3%	$222.9
Proved Undeveloped (PUD)	9.6	1.3	58.4	20.6	52.8%	$213.7
Total 1P Reserves (Excluding ARO)	**37.2**	**19.1**	**607.6**	**157.6**	**35.7%**	**$1,621.9**
Probable Reserves (PROB)	35.7	6.4	204.0	76.1	55.3%	$1,022.9
Total 2P Reserves (Excluding ARO)	**72.9**	**25.5**	**811.7**	**233.7**	**42.1%**	**$2,644.8**
Possible Reserves (POSS)	54.7	8.4	268.4	107.8	58.5%	$1,631.8
Total 3P Reserves (Excluding ARO)	**127.6**	**33.9**	**1,080.0**	**341.5**	**47.3%**	**$4,276.5**
1P Asset Retirement Obligations (ARO)						($241.1)

1) Based on year-end 2021 reserve report at average realized SEC pricing of $66.55/BO and $3.60/MMbtu.
2) Pre-Tax PV-10 is a non-GAAP measure; see reconciliation in Appendix.
3) Pre-Tax PV-10 excluding 1P Asset Retirement Obligation.

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

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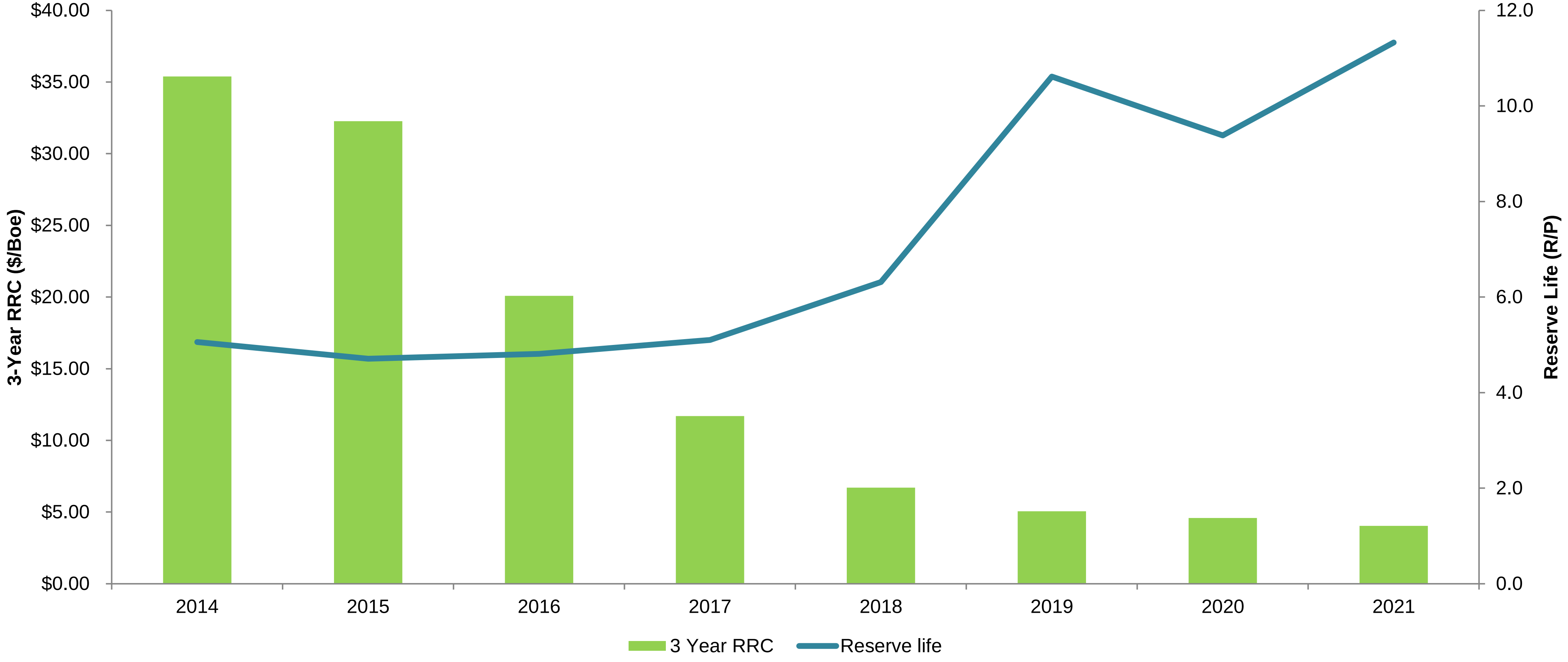
Since 2014, 3-year RRC Decreased ~89% While Reserve Life[2] Increased 124% from 5.1 to 11.3 Years



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.

Reserves: 3/02/22 NYMEX Strip Pricing[1]

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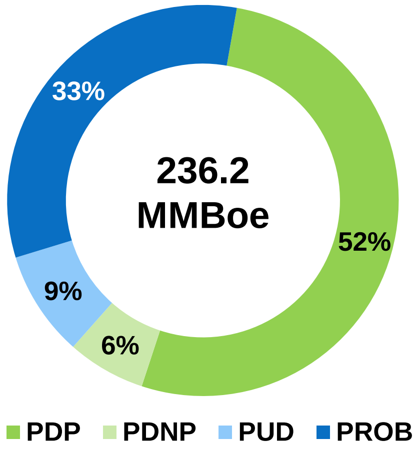
Reserve Category	Oil (MMBoe)	NGL (MMBoe)	Gas (Bcf)	Total (MMBoe)	% Liquids	Pre-Tax PV-10[2] ($MM)
Proved Developed Producing (PDP)	21.1	16.6	514.8	123.5	30.5%	$1,490.1
Proved Developed Non-Producing (PDNP)	6.8	1.4	42.4	15.3	53.9%	$279.1
Proved Undeveloped (PUD)	9.6	1.3	58.5	20.6	52.8%	$266.1
Total 1P Reserves (Excluding ARO)	**37.5**	**19.3**	**615.7**	**159.5**	**35.6%**	**$2,035.3**
Probable Reserves (PROB)	35.7	6.4	208.0	76.8	54.8%	$1,146.2
Total 2P Reserves Excluding ARO)	**73.2**	**25.8**	**823.7**	**236.2**	**41.9%**	**$3,181.5**
Possible Reserves (POSS)	54.6	8.4	266.0	107.3	58.7%	$1,780.2
Total 3P Reserves Excluding ARO)	**127.8**	**34.1**	**1,089.8**	**343.6**	**47.1%**	**$4,961.7**
1P Asset Retirement Obligations (ARO)						($241.1)

3/02/22 NYMEX Strip Prices (1P Life)

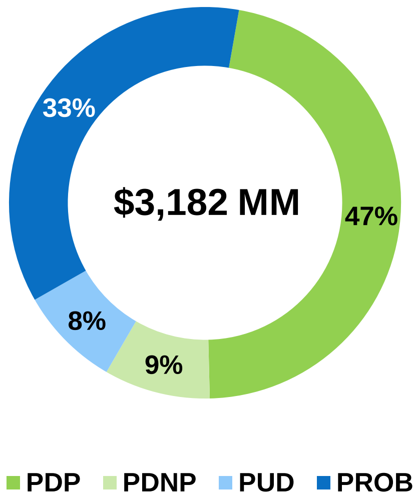
Oil $/Bbl
$73.65

Gas $/MMbtu
$3.83

2P SEC Reserves[1]



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



1) Based on year-end 2021 reserve report using strip pricing as of 3/02/22 NYMEX pricing (1P Life) of $73.65/BO and $3.83/MMbtu
2) Pre-Tax PV-10 is a non-GAAP measure.
3) Pre-Tax PV-10 excluding 1P Asset Retirement Obligation.

Strategic Capital Allocation Plan

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

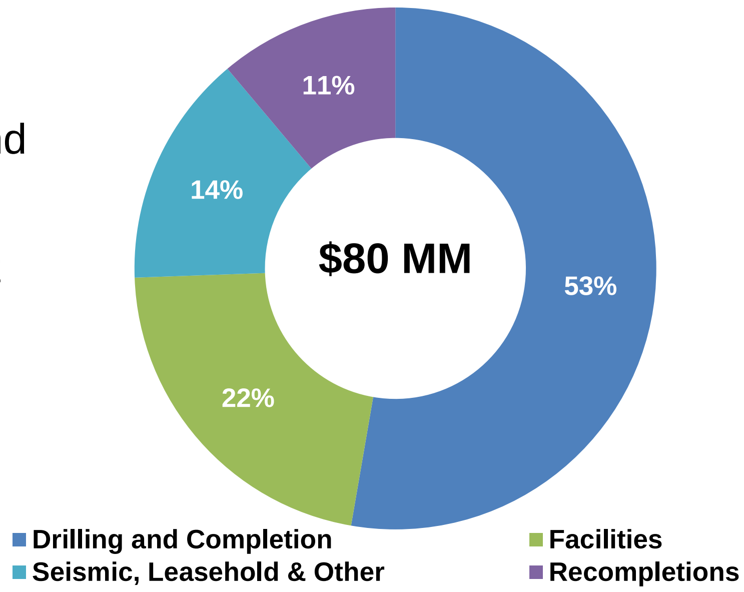
Maintain a Prudent Balance Sheet and Use Free Cash Flow to Grow Opportunistically and Reduce Debt

2022 Capital Expenditure and P&A Budget

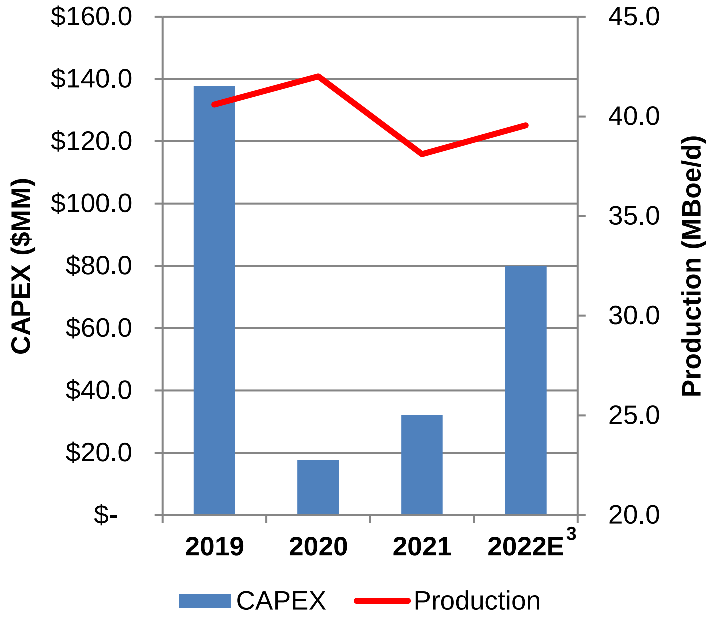
W&T OFFSHORE

- ✓ 2022 CAPEX[1] guidance:
  - $70 - $90 MM
  - Plans for 1 deepwater well and 3 shelf wells, as wells as facilities, seismic, and recompletions
  - Spending equally weighted throughout year
- ✓ 2022 P&A guidance:
  - $55 - $75 MM
  - Current year activity driven by obligations and prior deferrals on terminated leases with BSEE

CAPEX Allocation[1,2]



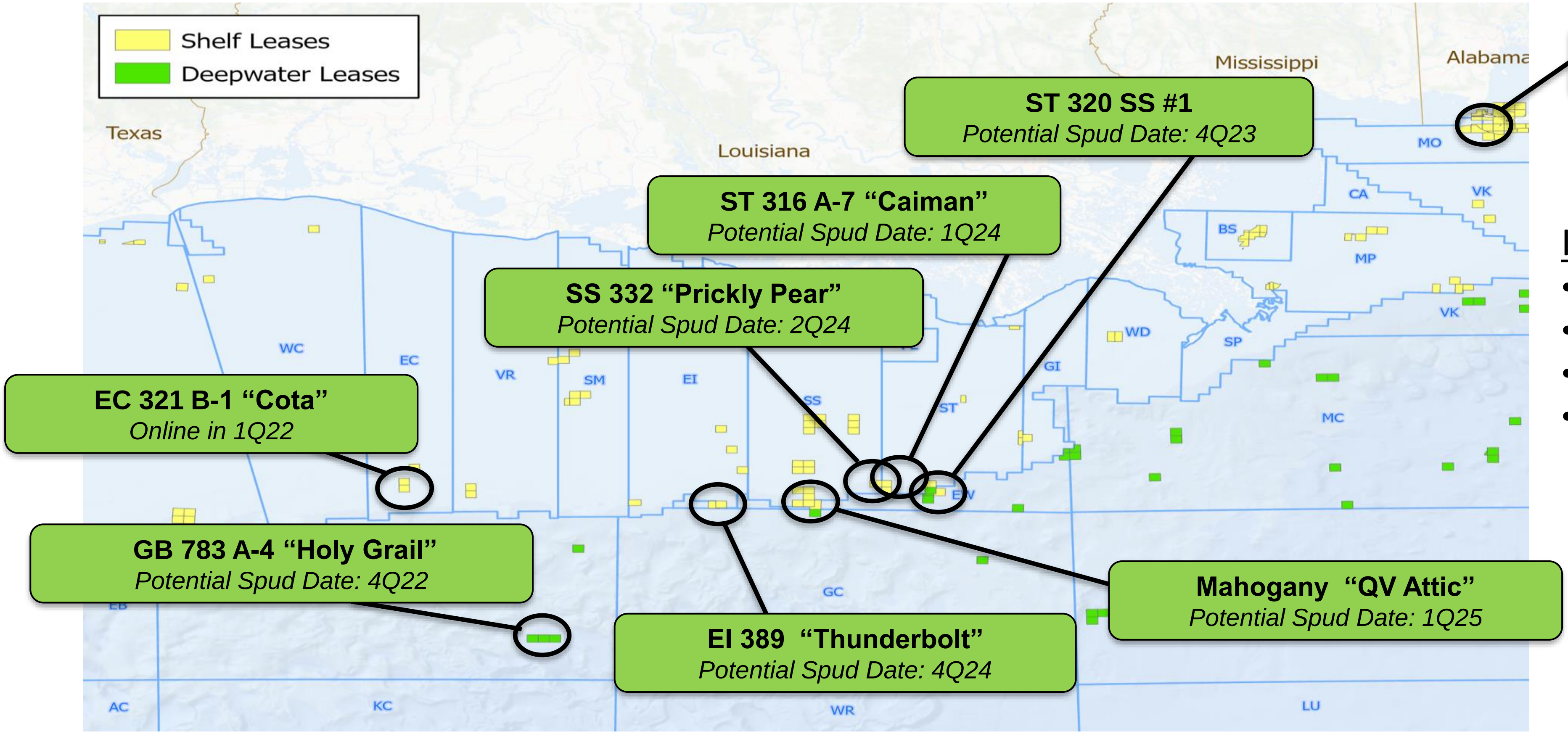
Production vs Capex



2022 CAPEX Includes More Capital for Drilling

1) Accrual basis capital expenditures only.
2) Based on midpoint of 2022 forecast.
3) 2022E is mid-point of annual guidance range.

Select Opportunities and Potential Spud Dates



Inventory Highlights

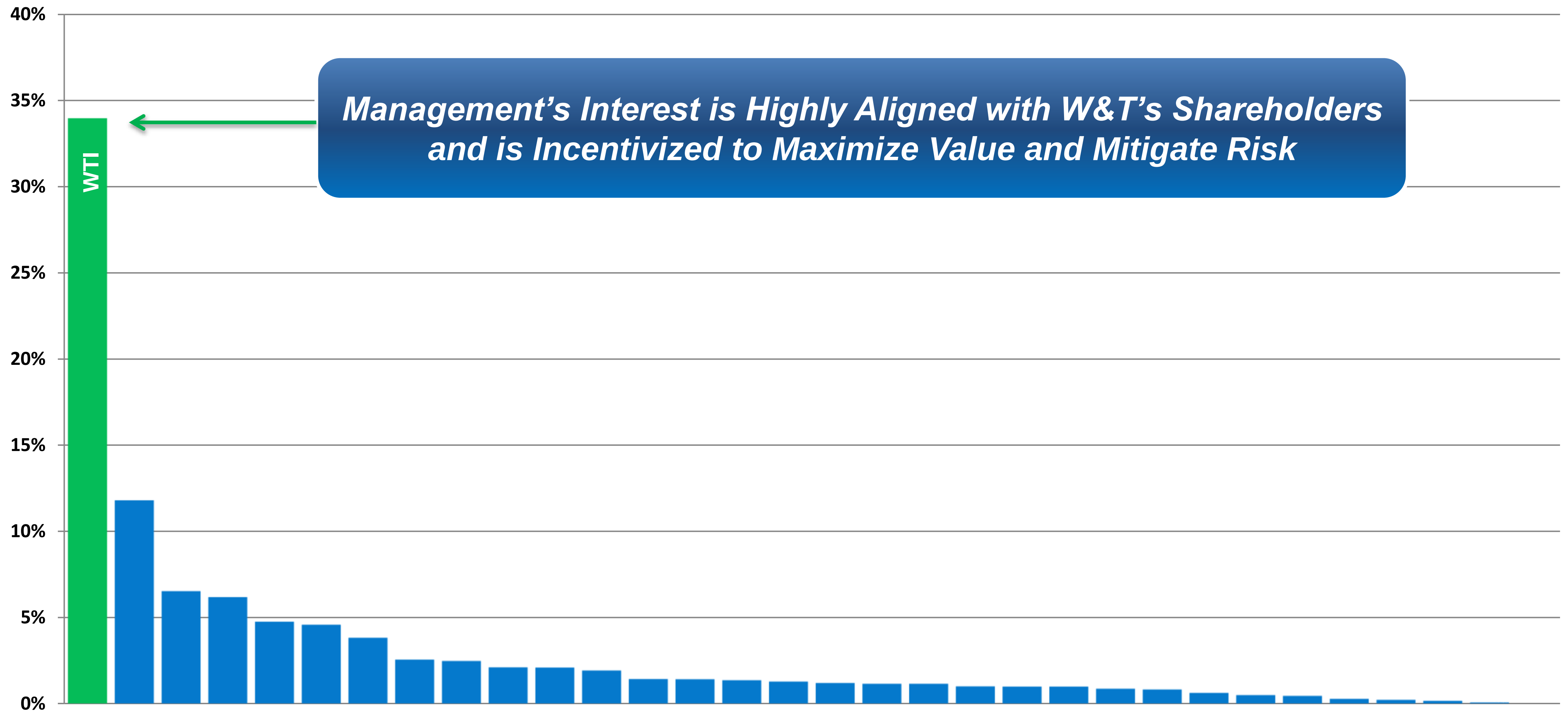
- 38 E&P Opportunities
- 79% Avg Working Interest
- 87% Operated
- 74% HBP

38 Opportunities with 16 Platform Wells and 22 Subsea Tiebacks (all < 15 miles) with an Estimated 3P Resource Potential of ~ 300 MMBoe

1) Inventory as of Feb 2022.

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.

Well-Positioned for Success

W&T OFFSHORE

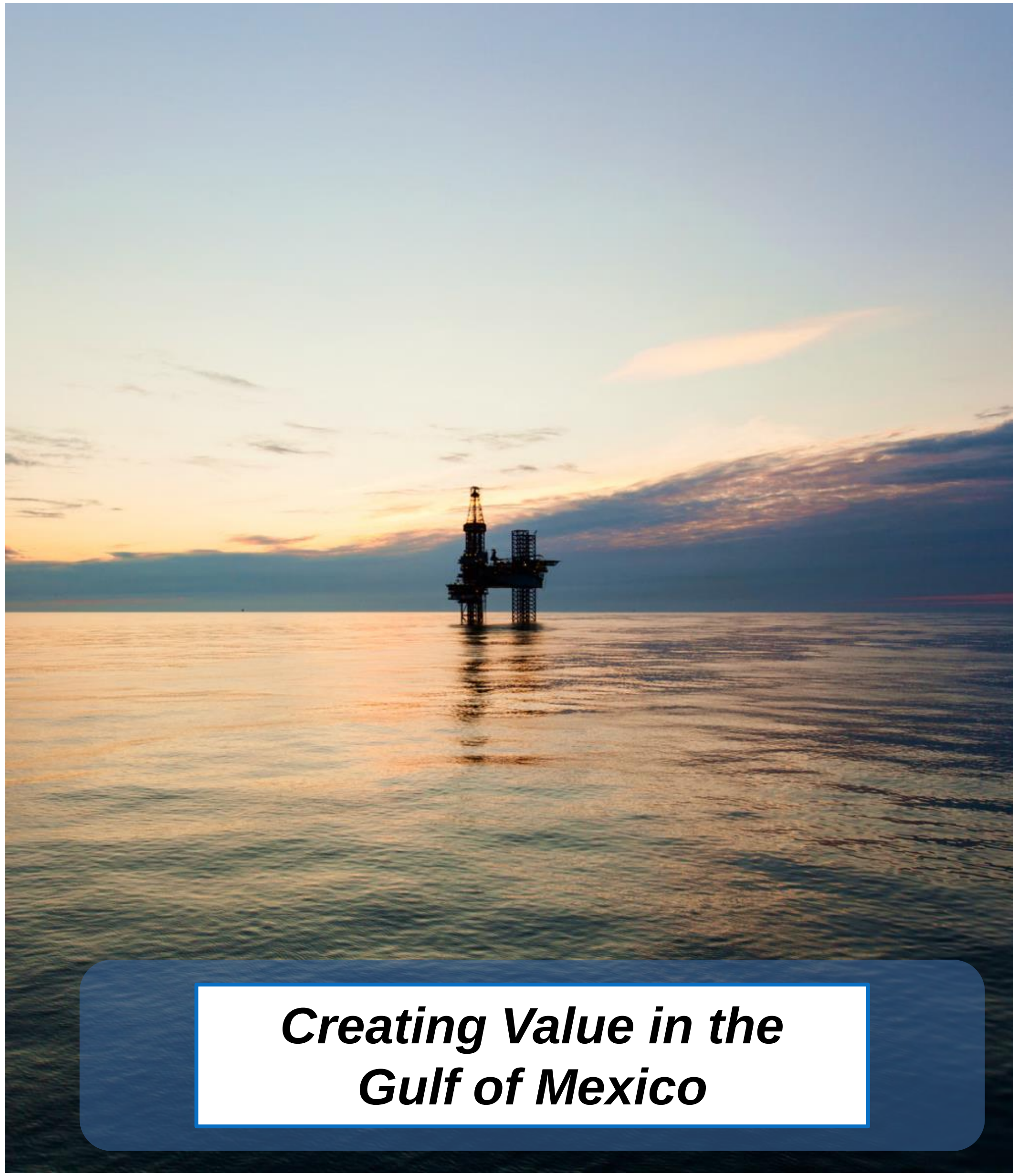
Nearly Four Decades of Safe Operations in the Gulf of Mexico

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



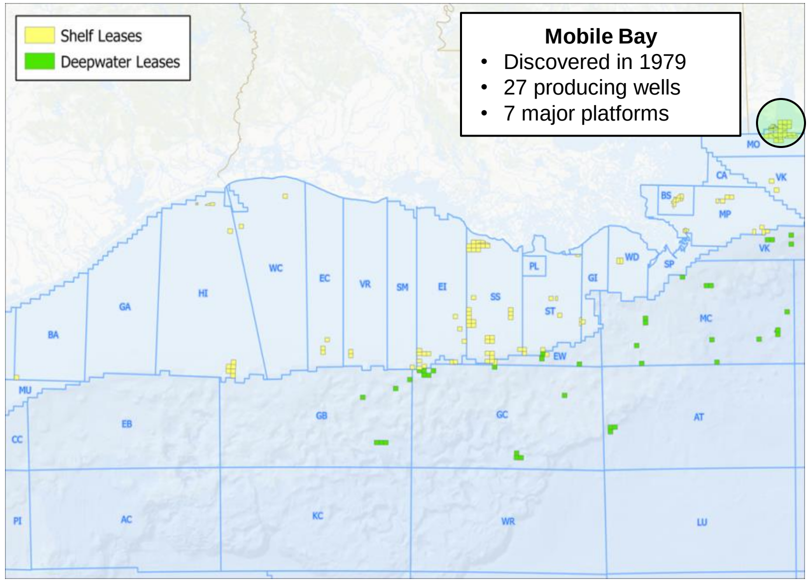
Creating Value in the Gulf of Mexico

Appendix

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
- ✓ Year-end 2021 proved reserves of ~78 MMBoe[1] of which the vast majority are proved developed producing (84% natural gas); 4Q21 avg production 15.0 MBoe/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***

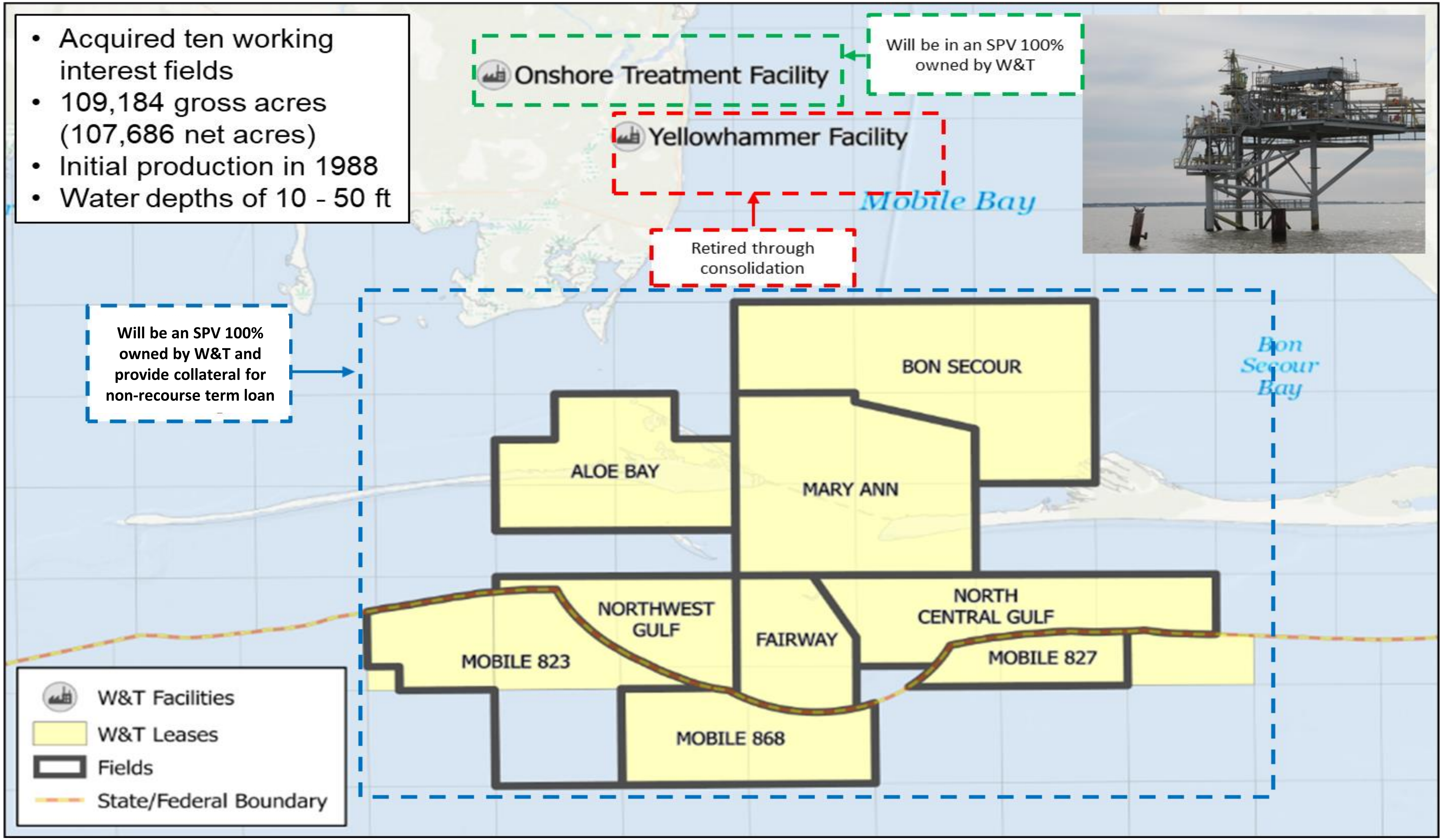
Low Decline, Long-Life, Mostly PDP



NYSE: WTI

1) Based on year-end 2021 reserve report at 12/31/21 by NSAI at average realized SEC pricing (1P Life) of $66.55/BO and $3.60/MMbtu.

Mobile Bay Area – Asset Map

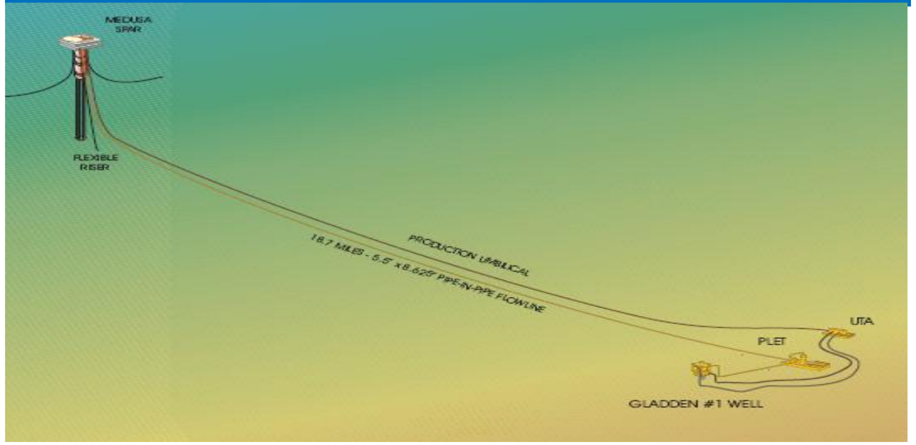


Significant Infrastructure Advantage

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

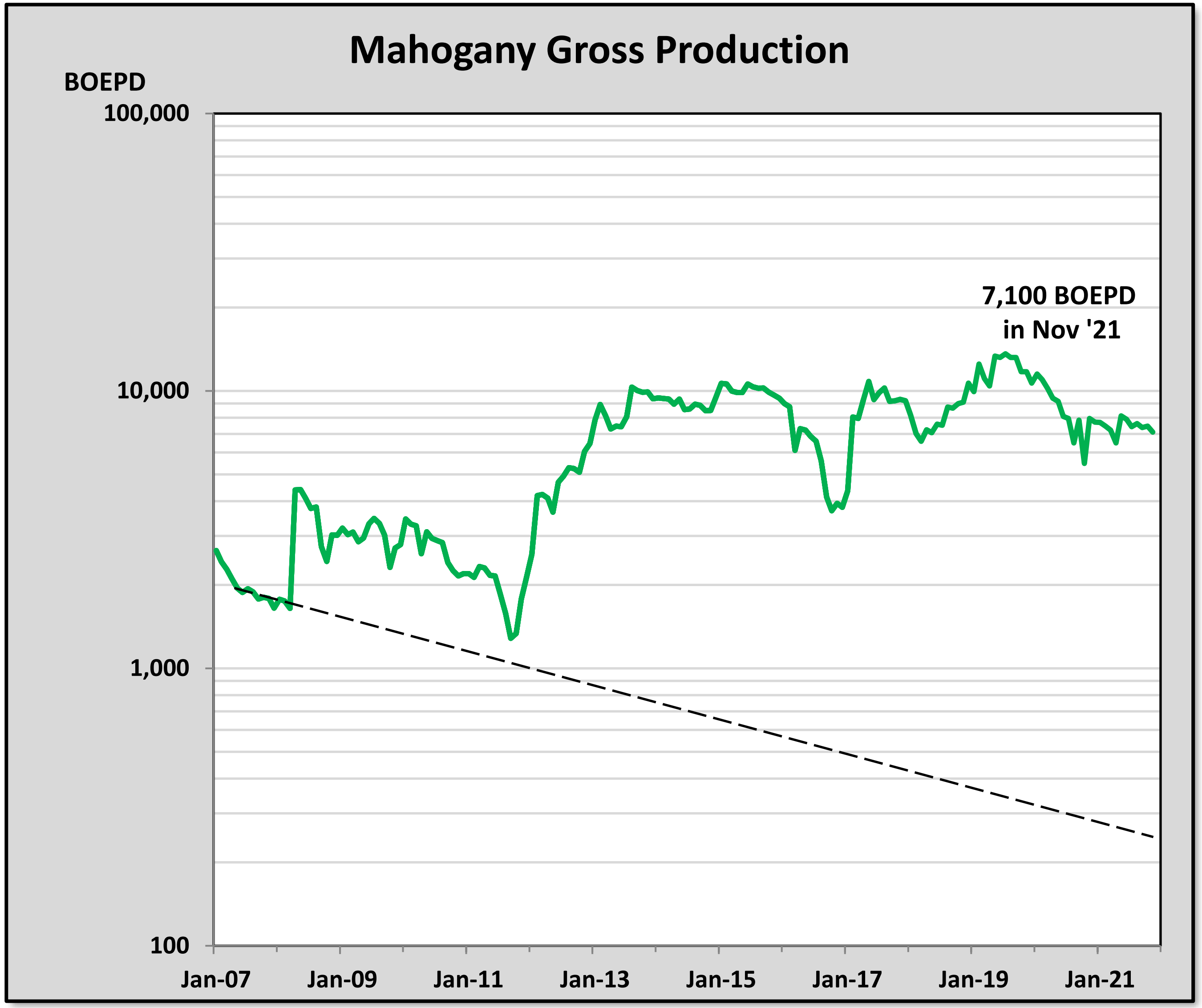
Platform Rig on infield production facility (EW 910 Area)

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 $7.5 MM, 2021 $12.2 MM*

SS 349 Field ("Mahogany") Case Study



SS 349 Field ("Mahogany")

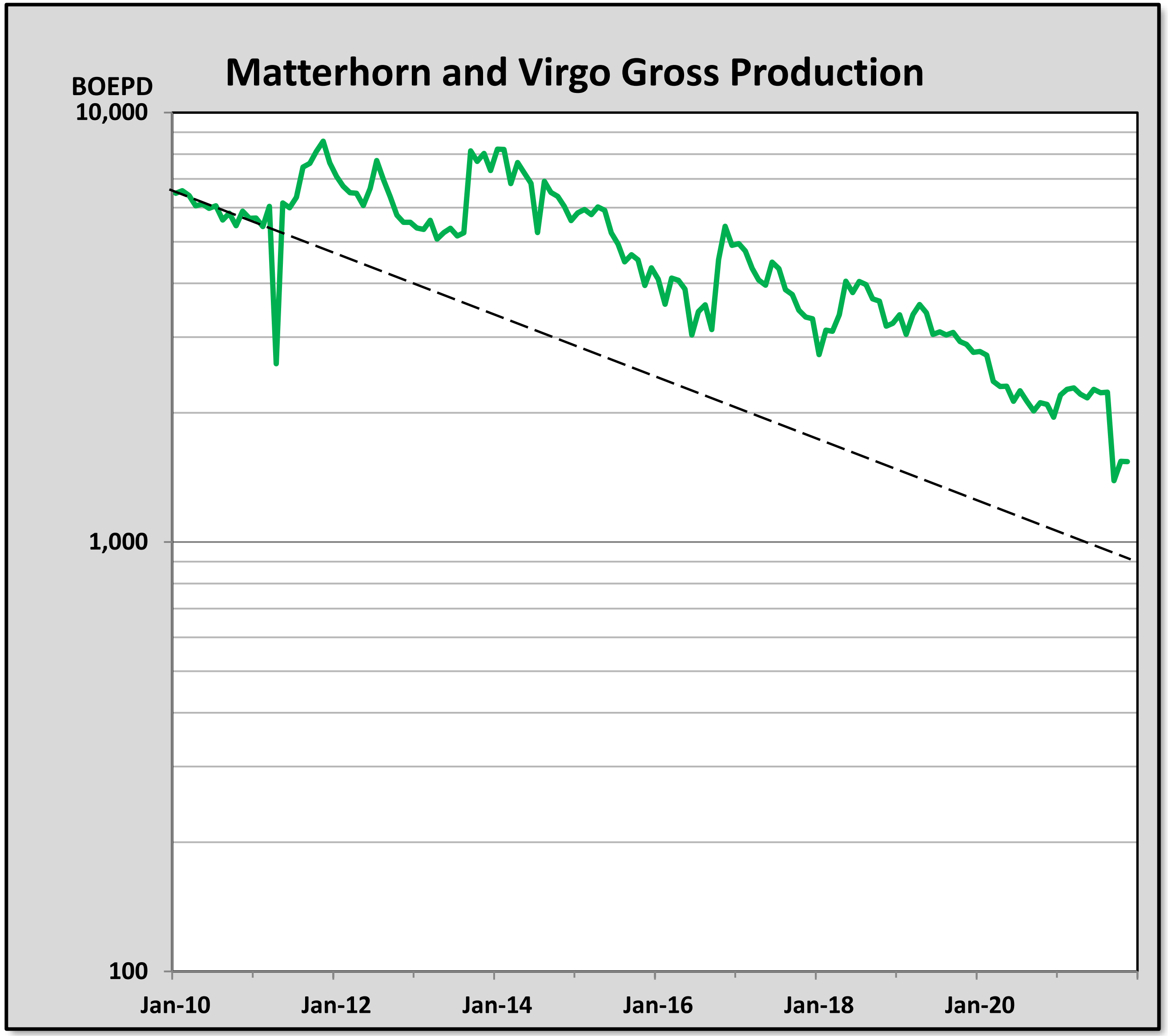
- ✓ WI: 100.0%, 360' Water Depth
- ✓ 1st commercially successful subsalt development in the Gulf of Mexico (initial production in 1997)
- ✓ Purchased interest in 2000, 2004 & 2008
- ✓ Cumulative purchase price of $175 MM
- ✓ Valuation
  - Total Net Cash Flow[1] $708 MM
  - Mid-year 2P PV10[2] net of ARO $795 MM
  - **Total Project Value[3] $1,503 MM**
- ✓ Have increased value by:
  - Development and exploration drilling
  - Performing recompletes
  - Reworks and performance optimization

Current Reserves[2]

1P Reserves:	20.2	MMBoe
2P Reserves:	43.5	MMBoe
3P Reserves:	77.9	MMBoe

1) From closing date including capex to December 31, 2021.
2) Based on year-end 2021 reserve report using strip pricing as of 3/02/22 NYMEX (1P Life) of $73.65/BO and $3.83/MMbtu
3) Total Net Cash Flow as of December 31, 2021, plus year-end 2021 2P PV10 value (including ARO).

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 $115 MM
- ✓ Valuation
  - Total Net Cash Flow[1] $501 MM
  - Mid-year 2P PV10[2] net of ARO $156 MM
  - **Total Project Value[3] $657 MM**
- ✓ Have increased value by:
  - Drilling sidetracks
  - Performing recompletes
  - Instituting waterflood
  - Entering processing arrangement (Over $70 million in processing revenues received to date)

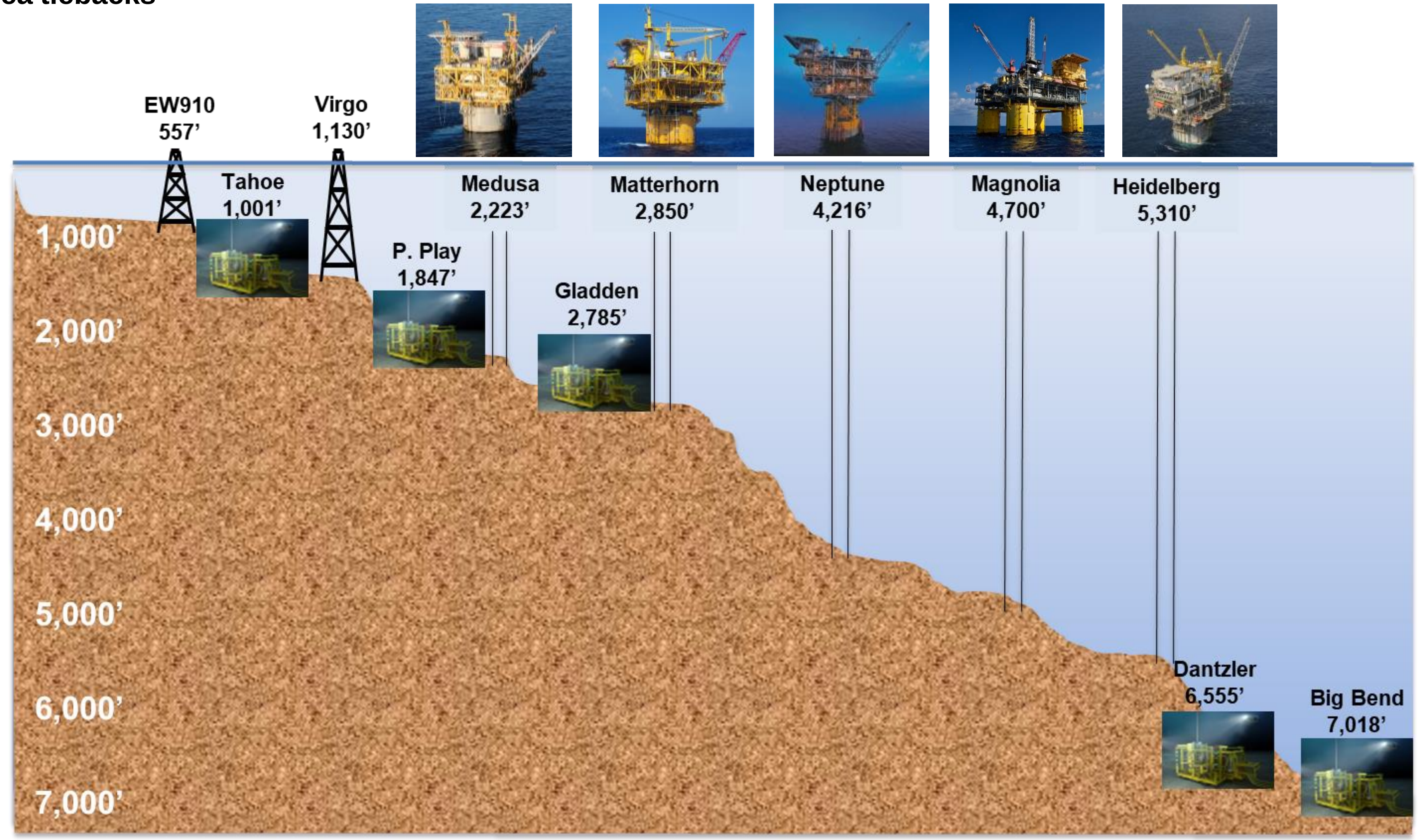
Current Reserves[2]

1P Reserves:	5.5	MMBoe
2P Reserves:	10.8	MMBoe
3P Reserves:	17.7	MMBoe

1) From closing date including capex to December 31, 2021.
2) Based on year-end 2021 reserve report using strip pricing as of 3/02/22 NYMEX (1P Life) of $73.65/BO and $3.83/MMbtu
3) Total Net Cash Flow as of December 31, 2021, plus year-end 2021 2P PV10 value (including ARO).

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**



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); currently bringing well online
- ✓ 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

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

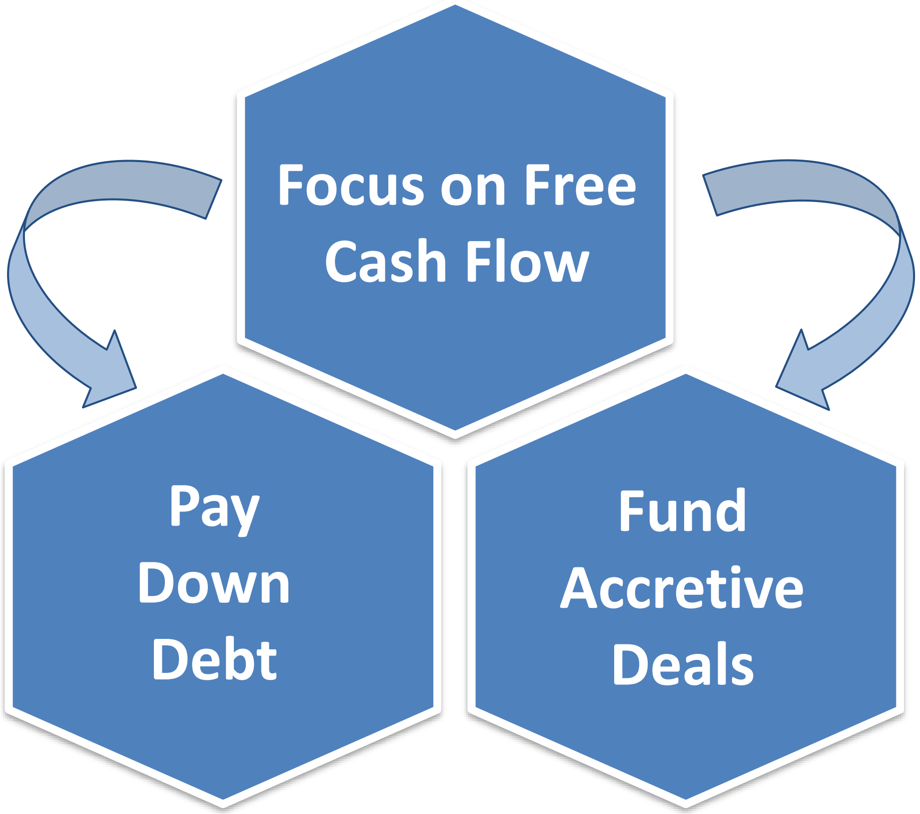
Success Rate[1]
2011 – 2020
> 90%

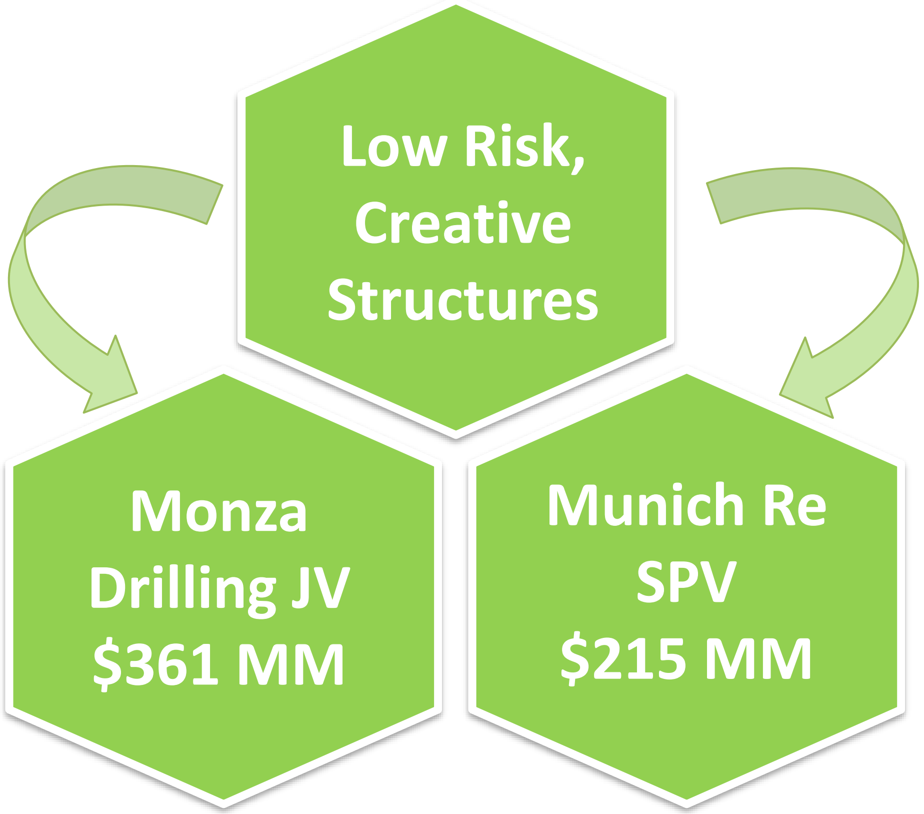
50 successful offshore wells drilled since 2011

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.

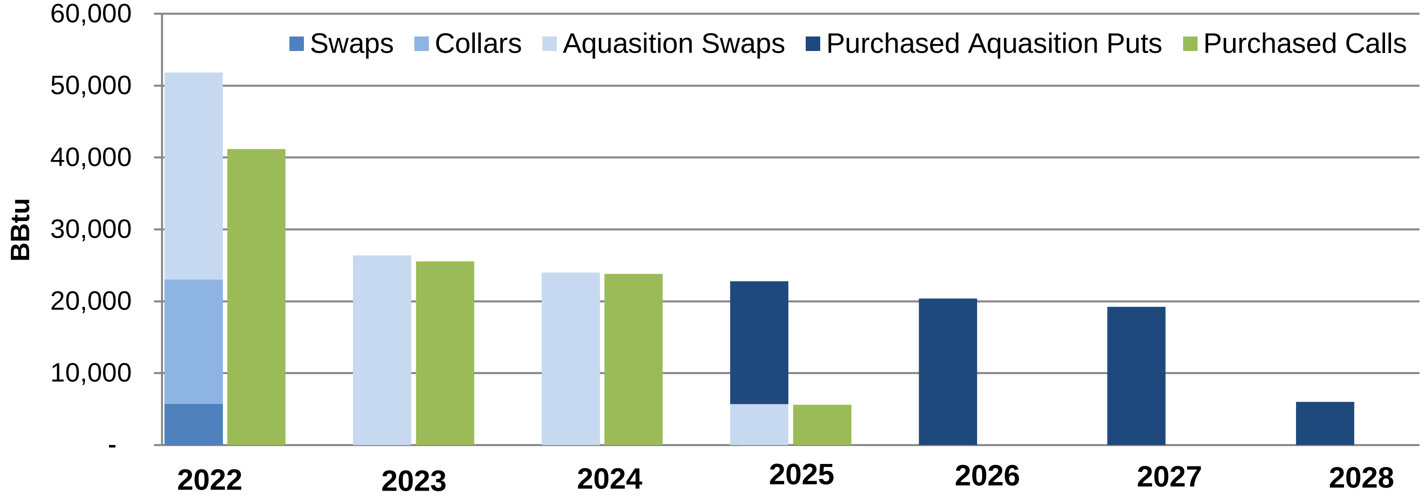
Financial Strategy



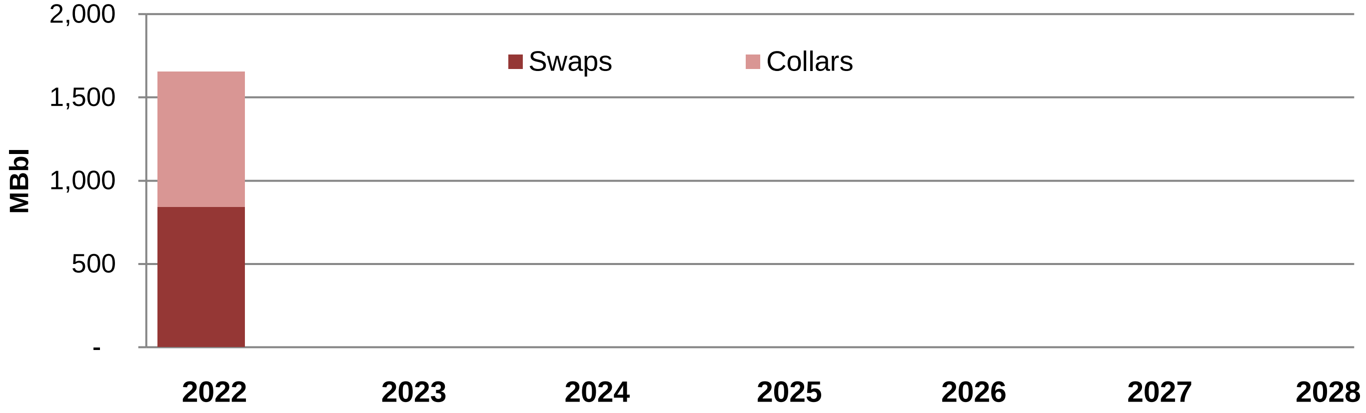


Hedge Program (March 8, 2022)

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.

Hedge Summary (as of March 8, 2022)

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
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
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
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 March 8, 2022)

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
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	-	-	$ -	-	-	$ -

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 adjusts for certain items that the Company believes affect comparability of operating results, including items that are generally non-recurring in nature or whose timing and/or amount cannot be reasonably estimated. These items include unrealized commodity derivative loss (gain), amortization of derivative premium, bad debt reserve, deferred tax benefit, gain on debt transactions, release of restricted funds, and litigation and other.

	Three Months Ended			Twelve Months Ended	
	December 31,	September 30,	December 31,	December 31,	
	2021	2021	2020	2021	2020
	(In thousands, except per share amounts) (Unaudited)				
Net income (loss)	$ 48,904	$ (37,964)	$ (8,947)	$ (41,478)	$ 37,790
Selected items					
Unrealized commodity derivative (gain) loss	(42,770)	43,111	11,456	82,758	10,040
Amortization of derivative premium	3,299	805	1,483	5,143	10,722
Bad debt reserve	315	1	(1,063)	323	(981)
Gain on debt transactions	-	-	-	-	(47,469)
Write-off debt issue costs	989		-	1,230	444
Litigation and other contingent loss	4,541	-	(2,708)	4,621	(2,708)
Release of restricted funds	(11,102)	-	-	(11,102)	-
Deferred tax expense (benefit)	10,637	(5,820)	(6,880)	(8,189)	(30,287)
Adjusted Net Income (Loss)	$ 14,813	$ 133	$ (6,659)	$ 33,306	$ (22,449)
Adjusted earnings (loss) per common share					
Basic	$ 0.10	$ -	$ (0.05)	$ 0.23	$ (0.16)
Diluted	$ 0.10	$ -	$ (0.05)	$ 0.23	$ (0.16)
Weighted Average Shares Outstanding					
Basic	142,389	142,297	141,721	142,271	141,622
Diluted	144,138	144,270	141,721	143,277	141,622

Non-GAAP Reconciliations

W&T OFFSHORE

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, release of restricted funds, 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

	Three Months Ended			Twelve Months Ended	
	December 31,	September 30,	December 31,	December 31,	
	2021	2021	2020	2021	2020
			(In thousands) (Unaudited)		
Net income (loss)	**$ 48,904**	**(37,964)**	**(8,947)**	**$ (41,478)**	**$ 37,790**
Interest expense, net	19,574	18,910	15,402	70,049	61,463
Income tax benefit	10,789	(5,902)	(6,858)	(8,057)	(30,153)
Depreciation, depletion, amortization and accretion	29,567	26,291	26,547	113,447	120,284
Unrealized commodity derivative (gain) loss	(42,770)	43,111	11,456	82,758	10,040
Amortization of derivative premium	3,299	805	1,483	5,143	10,722
Bad debt reserve	315	1	(1,063)	323	(981)
Write-off debt issue costs	989	-	-	1,230	444
Non-cash incentive compensation	1,585	859	817	3,364	3,959
Gain on debt transactions	-	-	-	-	(47,469)
Litigation and other contingent loss	4,541	-	(2,708)	4,621	(2,708)
Release of restricted funds	(11,102)	-	-	(11,102)	-
Adjusted EBITDA	**$ 65,691**	**$ 46,111**	**$ 36,129**	**$ 220,298**	**$ 163,391**
Investment in oil and natural gas properties and equipment	(16,037)	(10,169)	(4,678)	(32,062)	(17,632)
Purchases of furniture, fixtures and other	-	-	(460)	2	(530)
Asset retirement obligation settlements	(7,565)	(8,531)	(551)	(27,309)	(3,339)
Interest expense, net	(19,574)	(18,910)	(15,402)	(70,049)	(61,463)
Free Cash Flow	**$ 22,515**	**$ 8,501**	**$ 15,038**	**$ 90,880**	**$ 80,427**

Non-GAAP Reconciliations

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	Three Months Ended			Twelve Months Ended	
	December 31, 2021	September 30, 2021	December 31, 2020	December 31, 2021	December 31, 2020
			(In thousands) (Unaudited)		
Net cash provided by operating activities	$ 22,376	$ 65,097	$ (6,229)	$ 133,668	$ 108,509
Bad debt reserve	315	1	(1,063)	323	(981)
Litigation and other contingent loss	4,541	-	(2,708)	4,621	(2,708)
Release of restricted funds	(11,102)	-	-	(11,102)	-
Amortization of debt items and other items	(1,471)	(1,128)	(1,583)	(5,325)	(6,390)
Current tax benefit (expense) (1)	152	(82)	22	132	134
Changes in derivatives receivable (payable) (1)	14,231	1,571	(1,758)	34,370	(626)
Changes in operating assets and liabilities, excluding asset retirement obligation settlements	9,510	(46,789)	33,495	(33,747)	651
Investment in oil and natural gas properties and equipment	(16,037)	(10,169)	(4,678)	(32,062)	(17,632)
Purchases of furniture, fixtures and other	-	-	(460)	2	(530)
Free Cash Flow	$ 22,515	$ 8,501	$ 15,038	$ 90,880	$ 80,427

(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	$ 10,789	$ (5,902)	$ (6,858)	$ (8,057)	$ (30,153)
Less: Deferred income taxes	10,637	(5,820)	(6,880)	(8,189)	(30,287)
Current tax benefit (expense)	$ 152	$ (82)	$ 22	$ 132	$ 134
Changes in derivatives receivable:					
Derivatives receivable (payable), end of period	$ (6,396)	$ (12,511)	$ (281)	$ (6,396)	$ (281)
Derivatives receivable (payable), beginning of period	12,511	7,289	(1,477)	282	(345)
Derivative premiums paid	8,116	6,793	-	40,484	-
Change in derivatives receivable (payable)	$ 14,231	$ 1,571	$ (1,758)	$ 34,370	$ (626)

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, 2021	
Present value of estimated future net revenues (PV-10)[1] ………………………………………………………	$	1,621.9
Present value of estimated ARO, discounted at 10% ……………………………………………………….	$	(241.1)
PV-10 after ARO …………………………………………………………………………………………….	$	1,380.8
Future income taxes, discounted at 10% …………………………………………………………………….	$	(224.8)
Standardized measure of discounted future net cash flows[2]…………………………………………………..	$	1,156.0

1) Based on year-end 2021 reserve report at 12/31/21 by NSAI at average realized SEC pricing (1P Life) of $66.55/BO and $3.60/MMBtu.
2) Company calculates Standardized measure of discounted future net cash flows annually for Form 10-K filing.

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