Capital One Securities 15th Annual Energy Conference

December 9, 2020

W&T OFFSHORE

37+ Years of Industry Leadership in the Gulf of Mexico

Forward-Looking Statement Disclosure

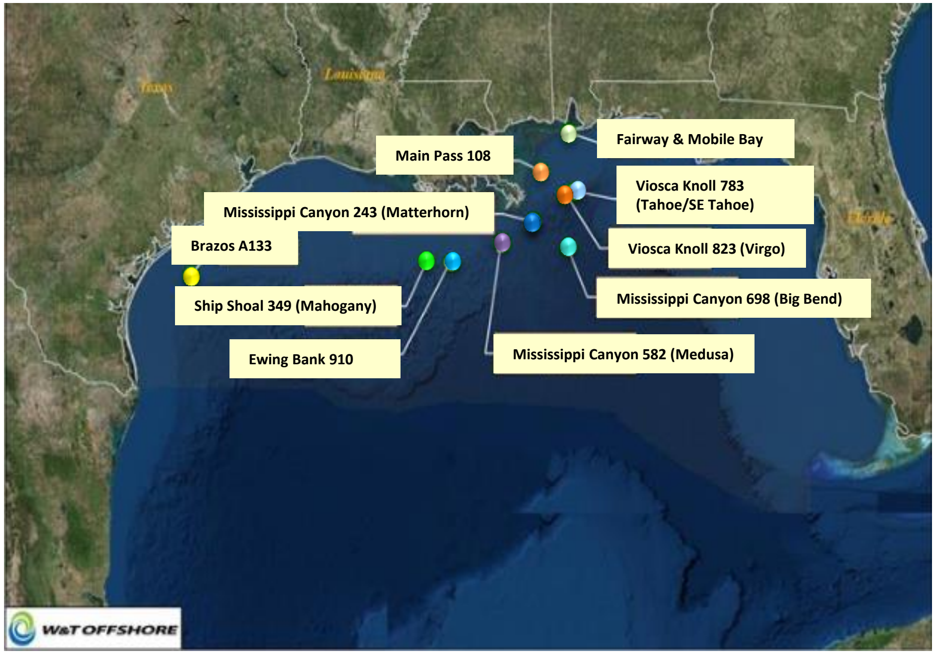
This presentation, contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements give our current expectations or forecasts of future events. They include 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, 2019 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.

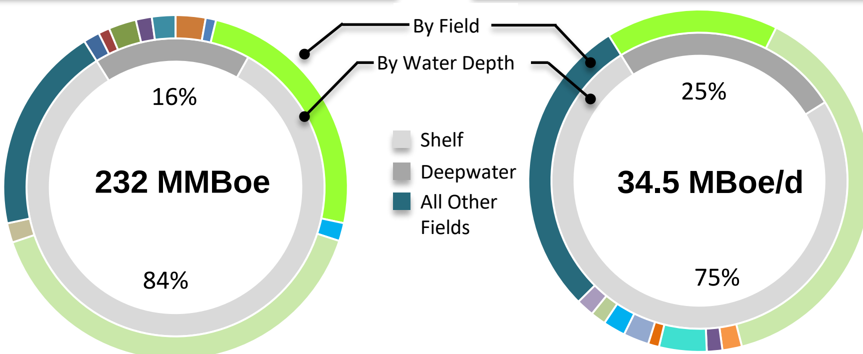
Company Snapshot



3Q'20 Average Production:	34.5 MBoe/d (48% liquids)
Producing Fields	50
Sept YTD 2020 Adjusted EBITDA[2]	$123.7 MM
1P Net Reserves[1] (MMBoe)	157
2P Net Reserves[1] (MMBoe)	232
3P Net Reserves[1] (MMBoe)	356
Liquids % of 1P Reserves:	34%

2P Reserves Mix[1]

3Q 2020 Avg. Daily Production[3]



Gulf of Mexico Shelf

- ~557,000 gross acres (~413,000 net)
- 75% of 3Q 2020 production of 34.5 MBoe/d
- Proved reserves of 139.3 MMBoe[1]
- 2P reserves of 194.9 MMBoe[1]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

- ~215,000 gross acres (~110,000 net)
- 25% of 3Q 2020 production of 34.5 MBoe/d
- Proved reserves of 18.1 MMBoe[1]
- 2P reserves of 37.1 MMBoe[1]
- Substantial upside with existing acreage

Federal vs State

- Production: Federal 60%, State 40%
- Net Acreage: Federal 82%, State 18%

Premium GOM Operator with 37+ 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) Based on mid-year 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/Mmbtu.
2) Adjusted EBITDA is a non-GAAP financial measure, see slide 45 for description of reconciling items to GAAP net income.
3) Breakout between Deepwater and Shelf reflects total Company production.

Q3 2020 and Recent Highlights

- ✓ Produced 34,459 Boe/d, or 3.2 million Boe (48% liquids), in 3Q'20, reflecting a 16% decrease from 3Q'19, primarily due to shut-ins related to the extraordinary 2020 hurricane season
- ✓ Reported a 3Q'20 net loss of $13.3 million or $0.09 per share and Adjusted Net Loss[1] of $19.9 million or $0.14 per share
- ✓ Generated Adjusted EBITDA[2] of $123.7 million for the first nine months of 2020
  - ✓ 3Q'20 Adjusted EBITDA[2] of $19.5 million, despite a significantly lower pricing environment and shut-in production due to hurricane activity, while capital expenditures were held to just $1.2 million
- ✓ Free Cash Flow[2] of $61.8 million for the first nine months of 2020
  - ✓ 3Q'20 Free Cash Flow[2] totaled $5.9 million
- ✓ Reduced total long-term debt by $97.5 million since December 31, 2019, resulting in approximately $8 million of annual interest expense savings
- ✓ Consolidation underway of natural gas treating facilities at Mobile Bay to be completed by year-end 2020, with expected future cost savings of ~$5 million per year beginning in 2021
- ✓ Responded to the current low oil price environment with definitive actions to maintain financial flexibility, protect cash flow and preserve future value:
  - ✓ Suspended all drilling activities and significantly reduced 2020 CAPEX estimate range to $15 - $25 million
  - ✓ Proactively curtailed production at selected operated oil-weighted fields
  - ✓ Implemented reductions in LOE without compromising safety or operational capabilities that resulted in LOE per Boe declining significantly from Q1'20
- ✓ Semi-annual redetermination of the borrowing base underway

Responding to the Current Environment by Reducing Costs, Capitalizing on Opportunities and Maintaining Free Cash Flow[2] Generation

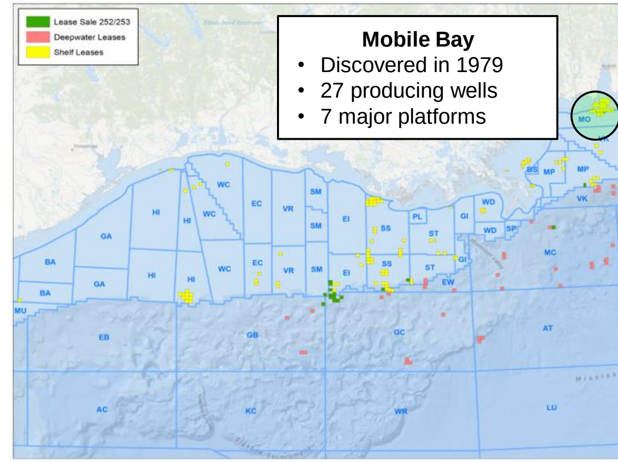
1) Adjusted Net Loss is a non-GAAP financial measure, see slide 46 for description of reconciling items to GAAP net loss.
2) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see slide 45 for description of reconciling items to GAAP net income.

Impact from 2020 Hurricanes

- The southern region of the U.S. has experienced the most active storm season since 2005
- Experienced multiple production shut-ins from June through early November due to the series of storms
  - Six out the eight storms required the Company to evacuate personnel
- Combination of storms and unplanned downtime at Mobile Bay reduced 3Q’20 production by 9,000 Boe/d
- W&T did not sustain any significant damage to its platforms or related infrastructure
- 4Q’20 expected to include ~$5 million in LOE related to repairs and restoring production
- On 12/8/20, W&T announced that the vast majority of shut-in production had been restored and increased its 4Q’20 production guidance to 34,700 – 36,900 Boe/d

Mobile Bay Acquisition – Key Highlights

- Acquired ExxonMobil's interests and operatorship in the eastern region of the Gulf of Mexico, offshore Alabama as well as related onshore processing facilities that are adjacent to existing properties owned and operated by W&T
- 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
- Midyear 2020 net proved reserves of 78 MMBoe[1] of which the vast majority are proved developed producing (88% natural gas)
- Contains future opportunities including Norphlet drilling leads and optimization of compression facilities
- Identified potential drilling opportunities that are planned for permitting in 2020 and drilled thereafter
- ***Consolidation underway of natural gas treating facilities at Mobile Bay to be completed by year-end, with expected future cost savings of $5 million per year beginning in 2021***

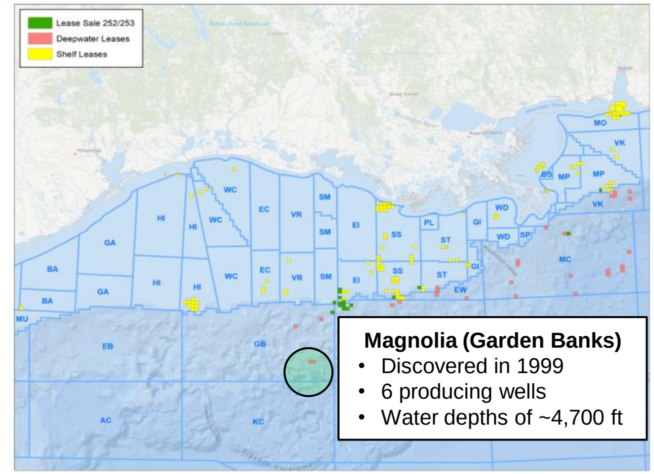


Low Decline, Long-Life, Mostly PDP

1) Based on mid-year 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/Mmbtu.

Magnolia Deepwater Acquisition – Key Highlights

- Acquired 100% working interest in and operatorship of the Magnolia Field in the central GOM, offshore Louisiana, in Garden Banks blocks 783 and 784 through two transactions
- Combined purchase price of $25.8 million[1] as of the effective date of October 1, 2019 and assumption of P&A liability
  - Net purchase price of $18.1 million as of the closing dates
- Sellers were ConocoPhillips (75% WI) and Marubeni Oil & Gas (25% WI)
- Midyear 2020 combined net proved reserves of 3.4 MMBoe of which 91% are proved developed producing and 80% are oil and 4% NGLs[2]
- Increased W&T's deepwater acreage by 11,520 gross and net acres
- Produced approximately 3,200 net Boe/d (80% oil) in the 2nd quarter 2020
- Decreased Lease Operating Expenses ~30% since acquiring working interest
- Provides additional upside from additional pay sands in existing wellbores and potential opportunities for future drilling
- Closed acquisition of 75% WI with ConocoPhillips on December 12, 2019; acquisition of remaining 25% WI from Marubeni closed on March 31, 2020; both acquisitions were funded with available cash on hand



Oil-Weighted Deepwater GOM Acquisition

1) Before normal and customary closing adjustments.
2) Based on mid-year 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/Mmbtu.

Corporate Responsibility

> ***"At W&T, we fully acknowledge our responsibility to our employees and contractors and the communities where we operate, and the importance of the ongoing protection of the environment".***
>
> **Tracy Krohn**, *Chairman and Chief Executive Officer*

Our Commitment

- Committed to developing and producing oil and gas resources in a safe and environmentally responsible manner, while meeting or exceeding all regulatory requirements
- Management allocates resources and tools necessary to meet expectations and performance objectives and strives to create a working environment that encourages open communication about HSE issues and concerns

Safety & Environmental

- Reduced the number of reportable spills by 61% from 2017 to 2019
- Lowered our Incidence of Non-Compliance/Component Ratio (as per BSEE standards) by 60% from 2017 to 2019 and in 2019 was 29% lower than the industry average
- Reduced our Incidence of Non-Compliance/Inspection Ratio (as per BSEE standards) by 70% from 2018 to 2019
- Recently purchased an infrared camera to survey all production facilities for fugitive hydrocarbon emissions
- Employ two certified safety professional to manage HSE programs at our facilities
- Employ four employee compliance technicians to conduct internal audits with respect to HSE compliance

Social

- We actively support charitable organizations in the communities where we operate
- We focus on helping children and families most in need, while aiding in the protection of the environment
- We support our employees who volunteer their time with these organizations

Operational Overview

W&T's Response to COVID19

- ✓ At our corporate offices, we instituted 100% remote work on March 23, 2020, and subsequently reopened our offices and implemented actions to protect our employees
- ✓ For our field operations, we instituted screening of all personnel prior to entry to heliports and shorebases used by W&T. This includes a questionnaire and temperature screening; and we worked with other operators on common procedures as these are shared facilities
  - ✓ Also applies to both gas plants and offshore Mobile Bay operations
- ✓ Daily temperature screenings at offshore and onshore facilities
- ✓ Implemented procedures for distancing and hygiene at all field locations
- ✓ Worked with helicopter providers to put in place procedures for transporting symptomatic personnel from offshore facilities
- ✓ We will continue to monitor the COVID-19 situation and follow the advice of government and health advisors

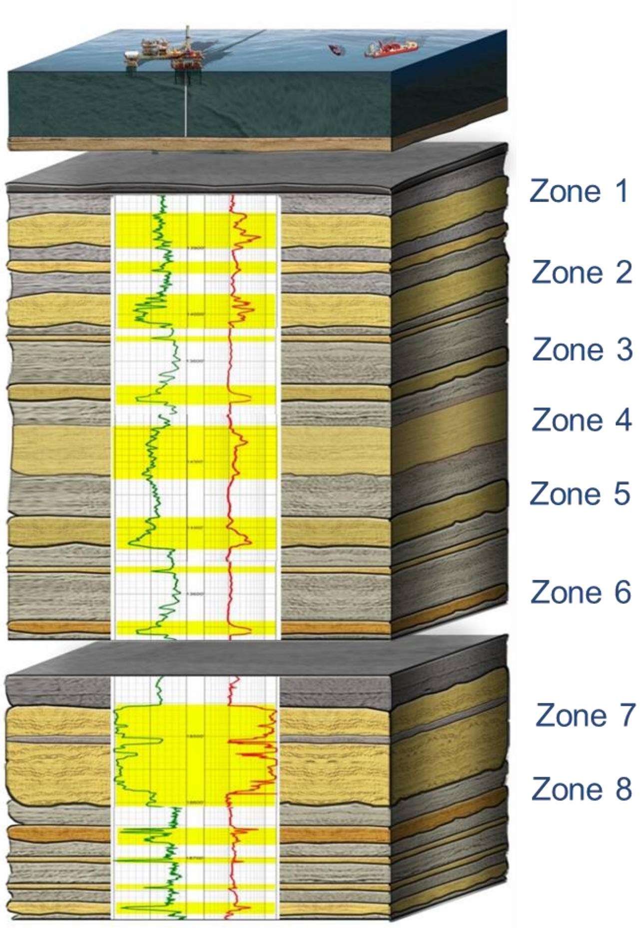
Gulf of Mexico – A Prolific & Unique Basin

Multiple stacked pay development opportunities

- Stacked reservoirs offer attractive primary production and recompletion opportunities
- Advanced seismic and geoscience greatly improve ability to identify drilling opportunities and enhance success

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

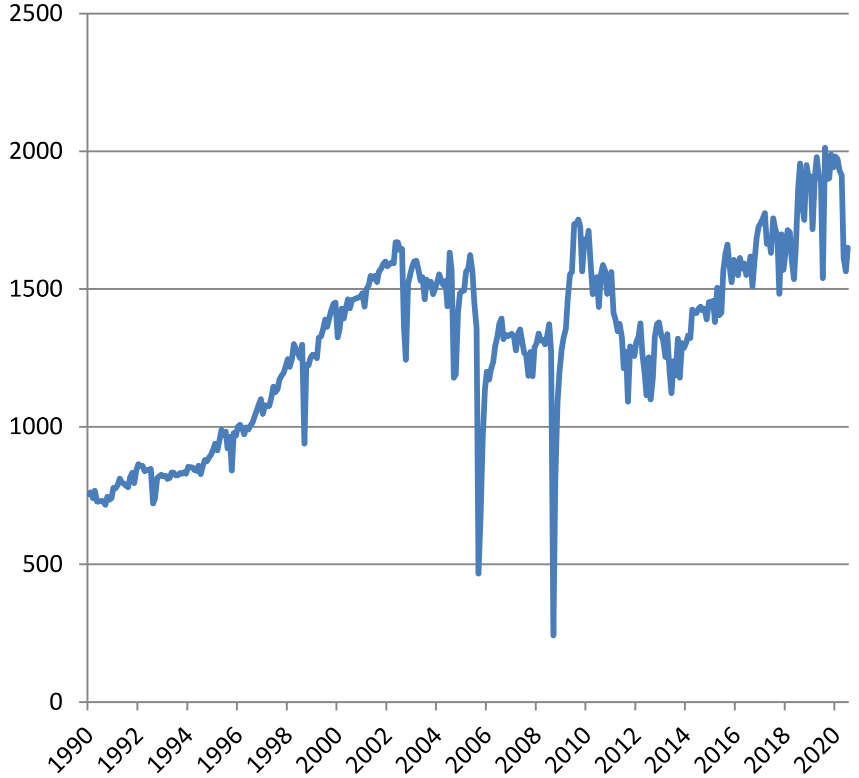
- Typical fields with high quality sands have drive mechanisms superior to primary depletion alone
- These fields enjoy incremental reserve adds annually, partly due to how reserve quantities are booked under SEC guidelines
- Fewer conventional wells required to develop fields



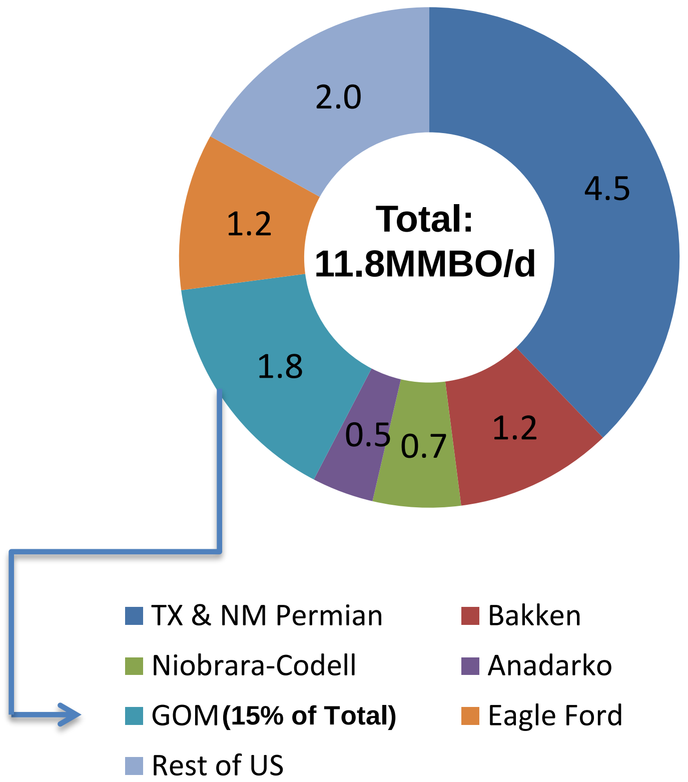
GOM Provides Better Porosity and Permeability than the Permian Basin

Gulf of Mexico – 2nd Largest U.S. Producing Basin

Gulf of Mexico Historical Oil Production[1]



2020 YTD US Oil Production by Key Region (MMBO/d)[1]

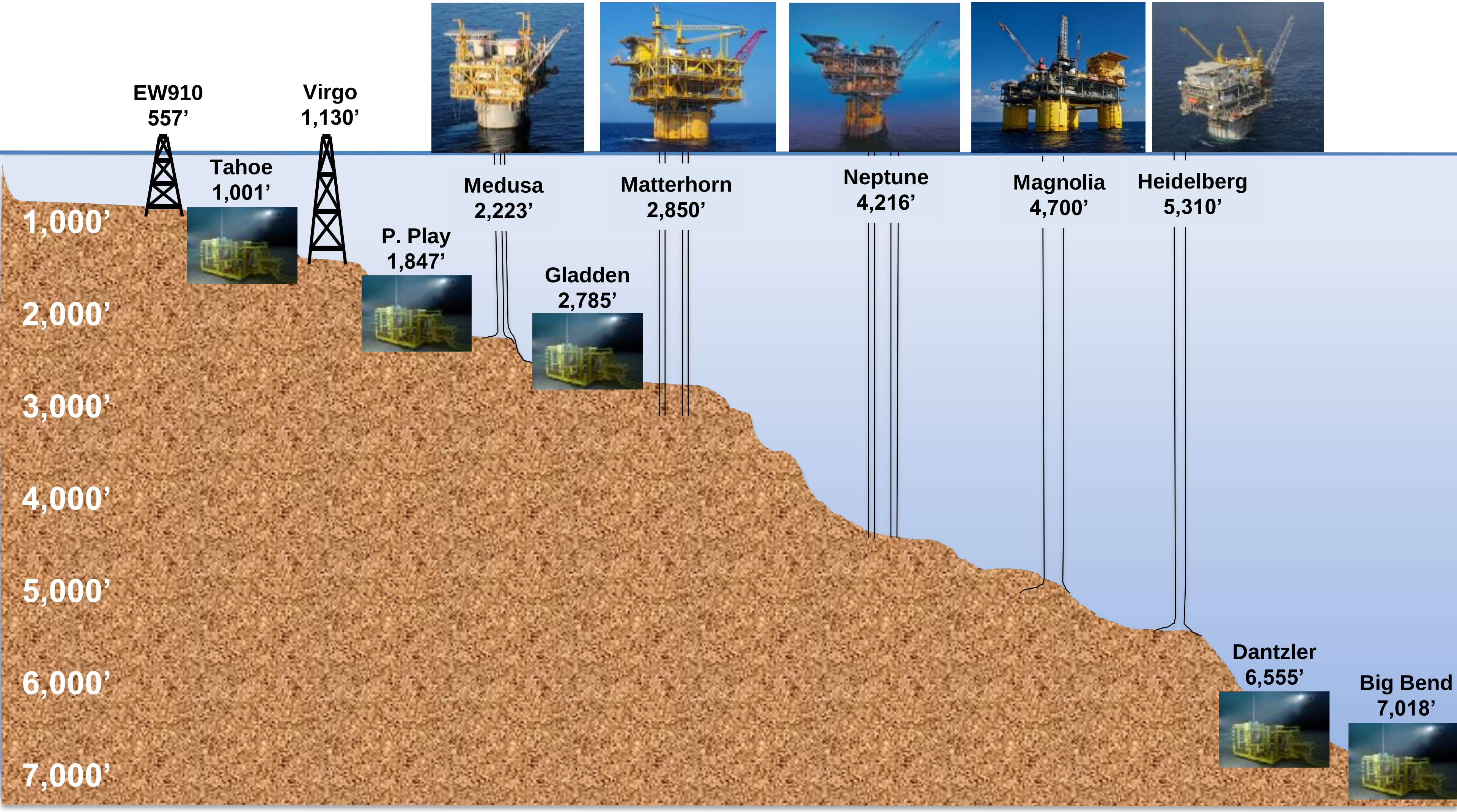


GOM Provides Unique Advantages: Low Decline Rates, World Class Porosity/Permeability and Significant Untapped Reserve Potential

1) Based on U.S. Energy Information Administration (EIA) data as of July 31, 2020.

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**



Rigorous Technical Evaluation Resulting in High Drilling Success

Process

1	2	3	4	5
Leads	Screening	Technical Evaluation	AFE Review	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

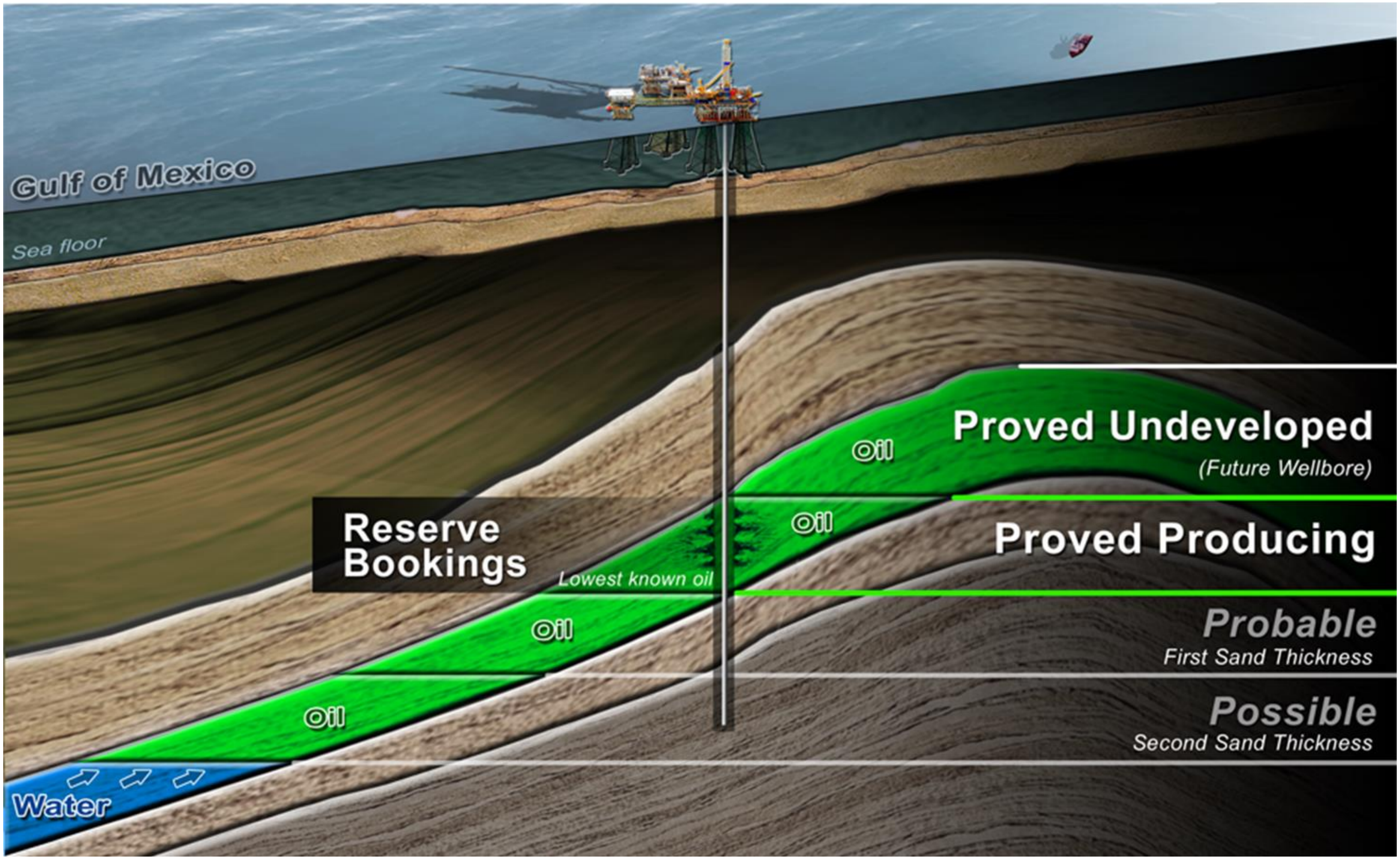
Success Rate[1]
2011 – 2020 YTD
> 90%

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.

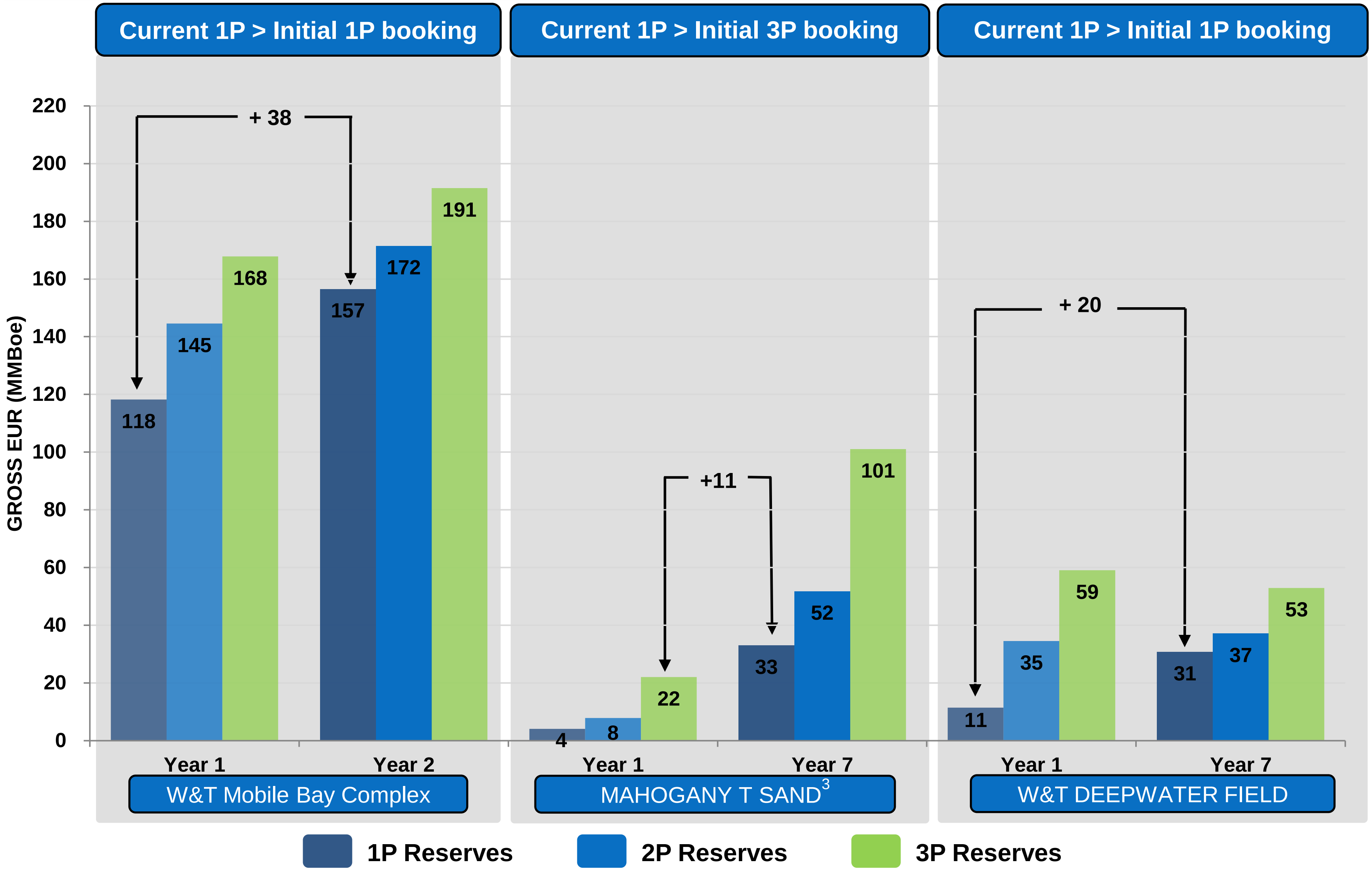
Incremental Probable and Possible Reserves May Be Produced at No Cost



Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

Significant W&T Reserve Appreciation From Initial Bookings

Actual Results [1,2]



1) Based on mid-year 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/Mmbtu.
2) 1P = Proved, 2P = Proved + Probable, 3P = Proved + Probable + Possible.
3) Initial 1P booking includes A-14 well only; Mid-Year 2020 1P booking includes A-14, A-18, A-19 & 1 PUD; 2P & 3P includes additional development wells.

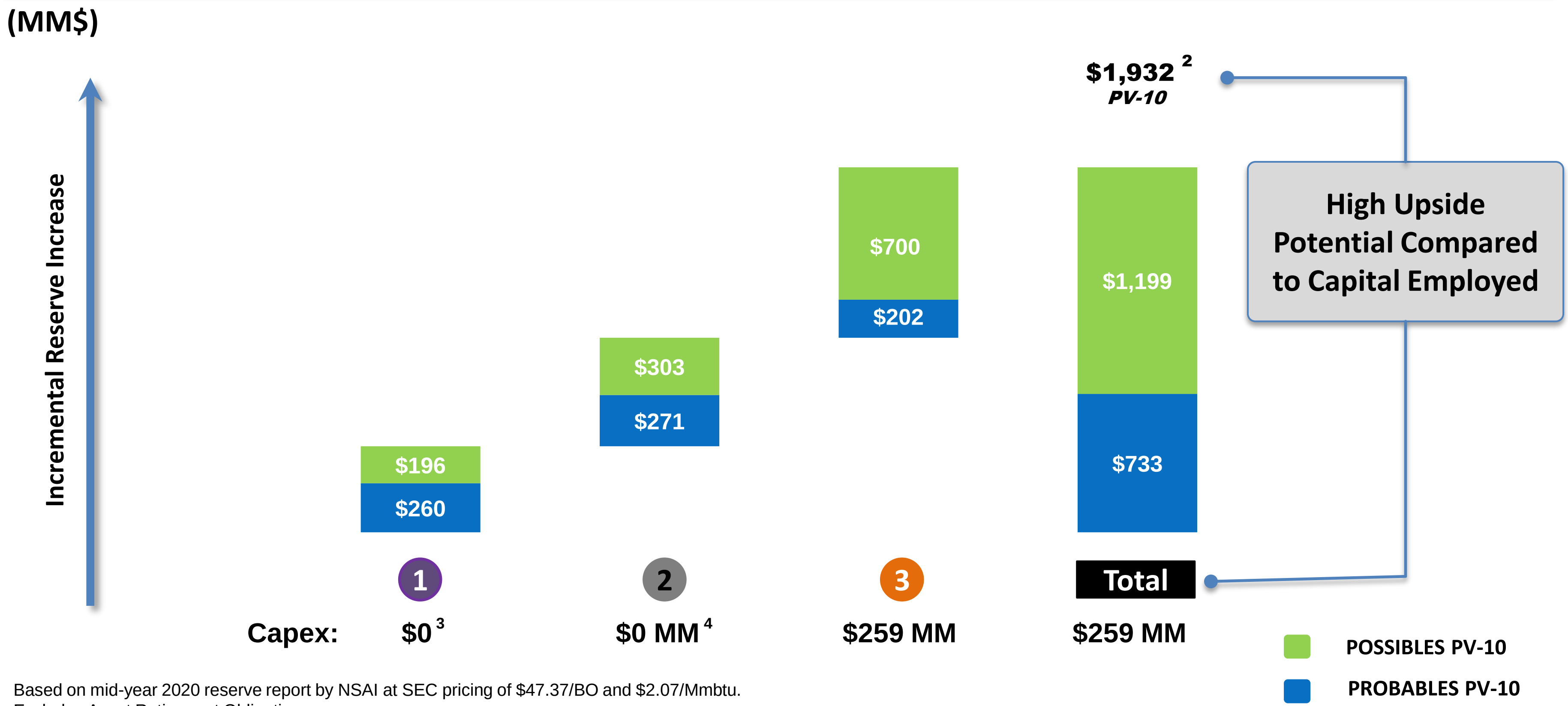
Realizing Incremental Probable and Possible Reserve Upside[1]

WTI focused on realizing the reserves upside and adding economic value across three 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 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/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 PNP and PUD reserves and therefore have associated future indirect CAPEX requirements.

History of Creating Long-Term Value From GOM Acquisitions

TOTAL
$115 MM
Paid out in Aug. 2011

Net average production[1] of 1,126 Boe/d from Matterhorn and Virgo.

Reserves[2]:		
	1P –	5.7 MMBoe
	2P –	10.6 MMBoe
	3P –	19.4 MMBoe

NEWFIELD
$206 MM
Paid out in Nov. 2014

Net average production[1] of 1,729 Boe/d from 78 offshore blocks, 65 of which are in deepwater.

Reserves[2]:		
	1P –	2.0 MMBoe
	2P –	4.2 MMBoe
	3P –	9.2 MMBoe

WOODSIDE
$55 MM
Paid out in Sep. 2019
Investments Post Acq.

Net average production[1] of 713 Boe/d from Neptune and 24 add'l blocks. One exploration well brought on production in 2014.

Reserves[2]:		
	1P –	1.4 MMBoe
	2P –	1.8 MMBoe
	3P –	2.2 MMBoe

COBALT
$17 MM
Paid out in Aug. 2018

Net average production[1] of 504 Boe/d from Green Canyon 859, 903, & 904.

Reserves[2]:		
	1P –	0.3 MMBoe
	2P –	0.6 MMBoe
	3P –	1.0 MMBoe

CONOCOPHILLIPS/ MARUBENI[4]
$18 MM
Closed December 2019 and March 2020

Net average production[1] of 3,200 Boe/d from Garden Banks 783 & 784 (Magnolia Field).

Reserves[2]:		
	1P –	3.4 MMBoe
	2P –	9.2 MMBoe
	3P –	16.1 MMBoe

2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020

SHELL
$116 MM
Paid out in Nov. 2012

Net average production[1] of 391 Boe/d from Tahoe and 6 other fields.

Reserves[2]:		
	1P –	0.4 MMBoe
	2P –	0.8 MMBoe
	3P –	0.9 MMBoe

SHELL/ MARUBENI[3]
$61 MM
Paid out in Oct. 2014

Net average production[1] of 3,215 Boe/d from Fairway Field.

Reserves[2]:		
	1P –	15.6 MMBoe
	2P –	16.8 MMBoe
	3P –	18.5 MMBoe

CALLON
$83 MM
Investments Post Acquisition

Net average production[1] of 343 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 –	6.1 MMBoe

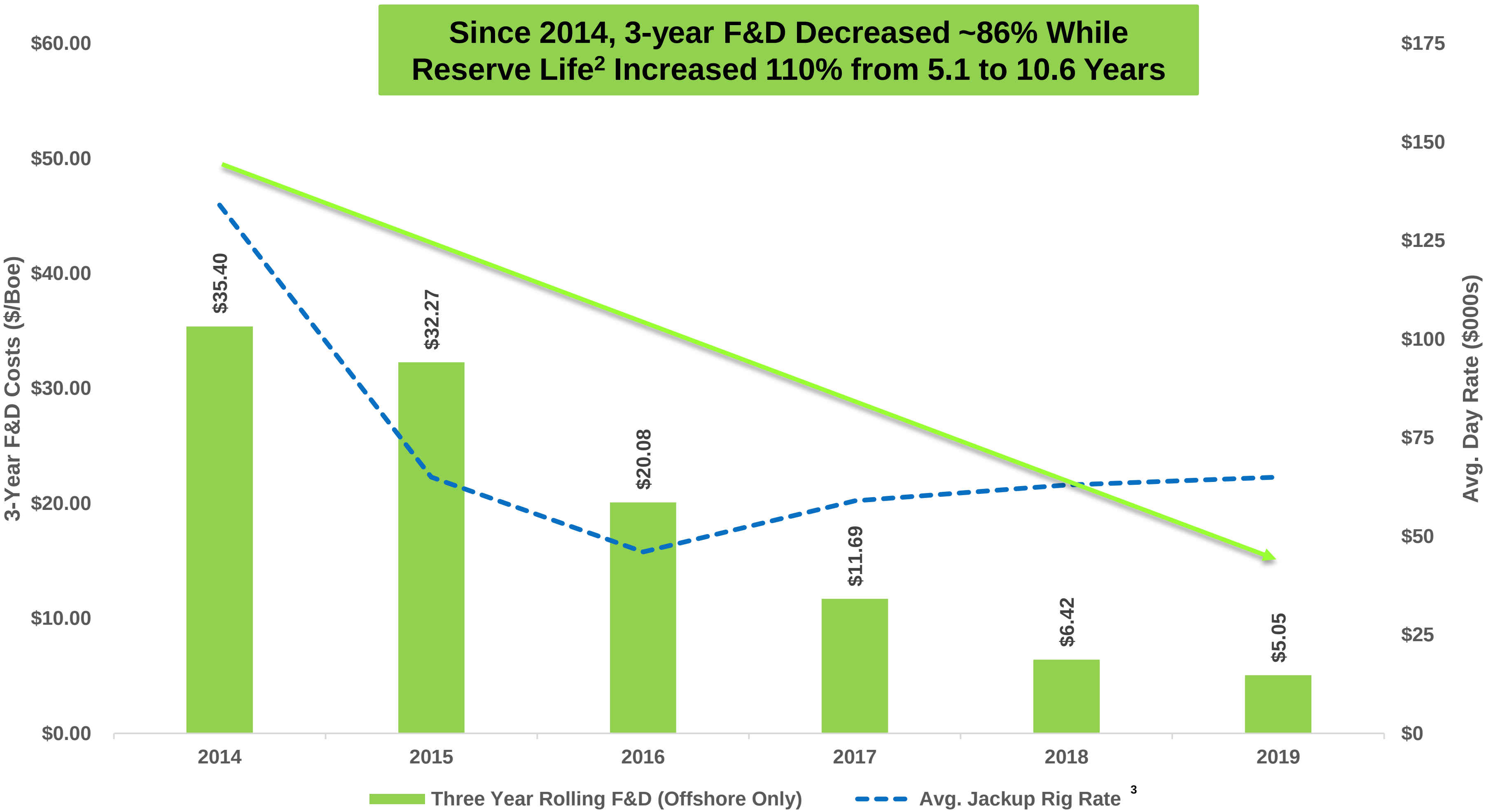
EXXONMOBIL
$168 MM
Closed August 30, 2019

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 –	76.5 MMBoe
	2P –	86.2 MMBoe
	3P –	98.0 MMBoe

1) Reflects 3Q'20 net average production except ConocoPhillips (Magnolia) which reflects 2Q'20 as 3Q'20 included extended field shut-in's.
2) Based on mid-year 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/Mmbtu.
3) Fairway Field: 8.9MMBoe(1P Reserves),12.8MMBoe(2P Reserves) acquired from Shell in 2011 for $43MM, 5.2MMBoe(1P Reserves), 5.8MMBoe(2P Reserves) acquired from Marubeni in 2014 for $18MM.
4) Magnolia Field: 4.0MMBoe(1P Reserves), 7.2MMBoe(2P Reserves) acquired from ConocoPhillips in December 2019 for $20MM, and 1.4MMBoe(1P Reserves), 2.5MMBoe (2P Reserves acquired from Marubeni in March 2020 for $5.8MM, as of the effective date.

Significant Declines in F&D Cost

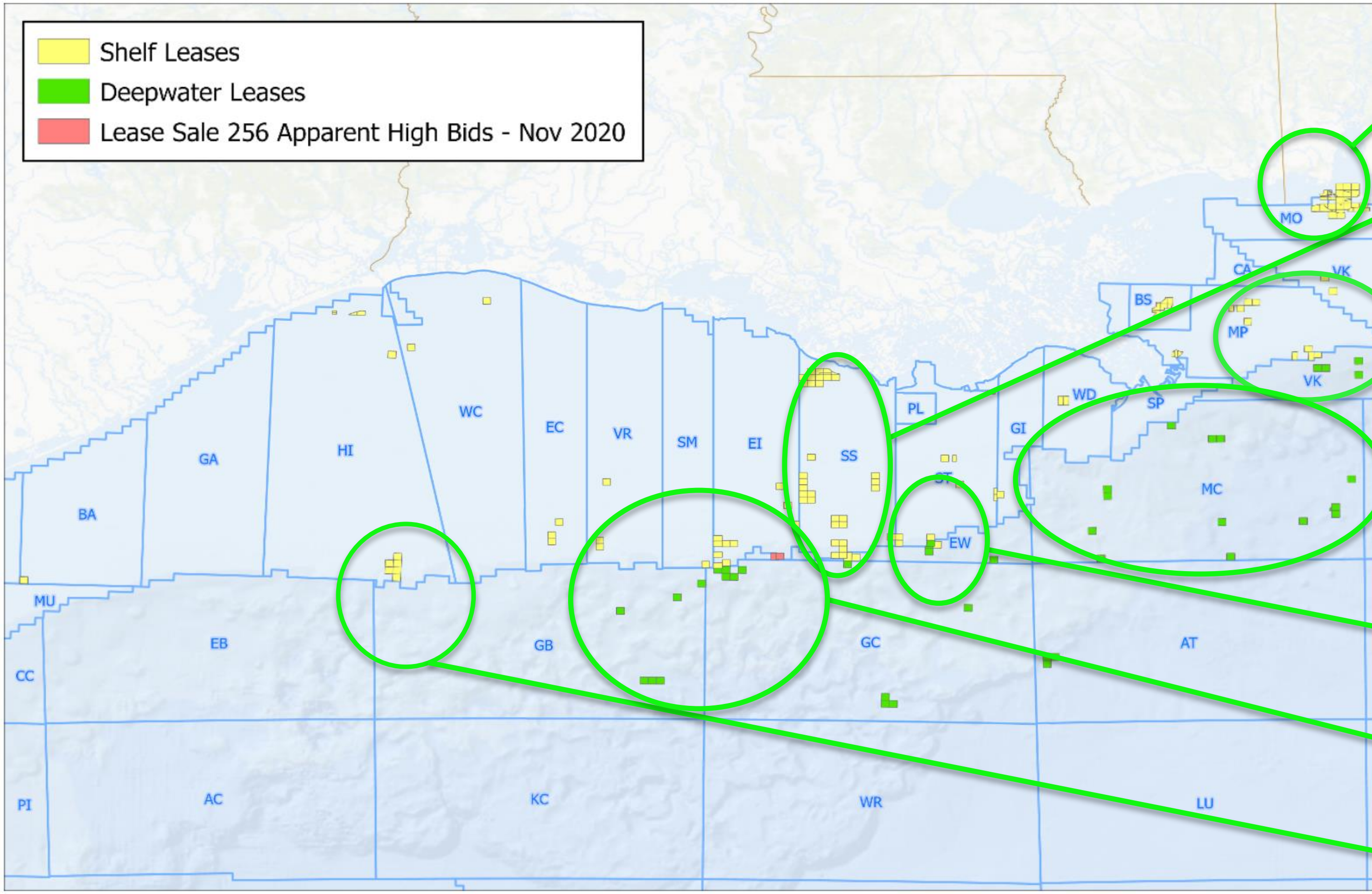


High Grading Projects, Sustainable Lower Service Costs, and Utilizing Existing Infrastructure Has Led to Lower F&D Costs

1) Based on NSAI offshore-only 1P Reserves at the end of each period and actual production for the year.
2) Year-end Proved Reserves divided by production for the year.
3) Company data.

Attractive Current Inventory (as of 11/20)

Selected Growth Opportunities



1 Exploration

9 Development
4 Exploration

2 Development

5 Development
6 Exploration

1 Development
3 Exploration

4 Development
8 Exploration

1 Exploration

~44 Opportunities with 19 Platform Wells and 25 Subsea Tiebacks (all < 15 miles) with an Estimated 3P Resource Potential of ~200 MMBoe

GOM Drilling Joint Venture

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

- Secured $361.4 MM commitment for the development of 14 pre-identified projects in the GOM with potential to upsize program over time with additional projects
  - Covers the total estimated cost of the 14 wells of $336 MM, plus contingency
  - Drilled and completed nine wells through December 31, 2019
  - Successfully drilled our first well of 2020 in the East Cameron 338/349 Field. Initial production is planned for the second half of 2021, subject to the commodity price environment and the completion of certain infrastructure projects
- 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
- HarbourVest Partners and Baker Hughes/GE are the two largest JV interest owners
- JV leverages BHGE's unique and flexible offering to potentially consolidate engineering, products and services and lower costs
- Upon private investors achieving certain return thresholds, W&T's share of well net revenue increases to 38.4%
- Allows 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

Strategic Capital Allocation Plan

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

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.

Debt Pay Down

Use free cash flow to reduce debt to protect our balance sheet and maintain financial flexibility.

Asset Acquisitions

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

Generate Shareholder Value

Leveraging 37+ 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

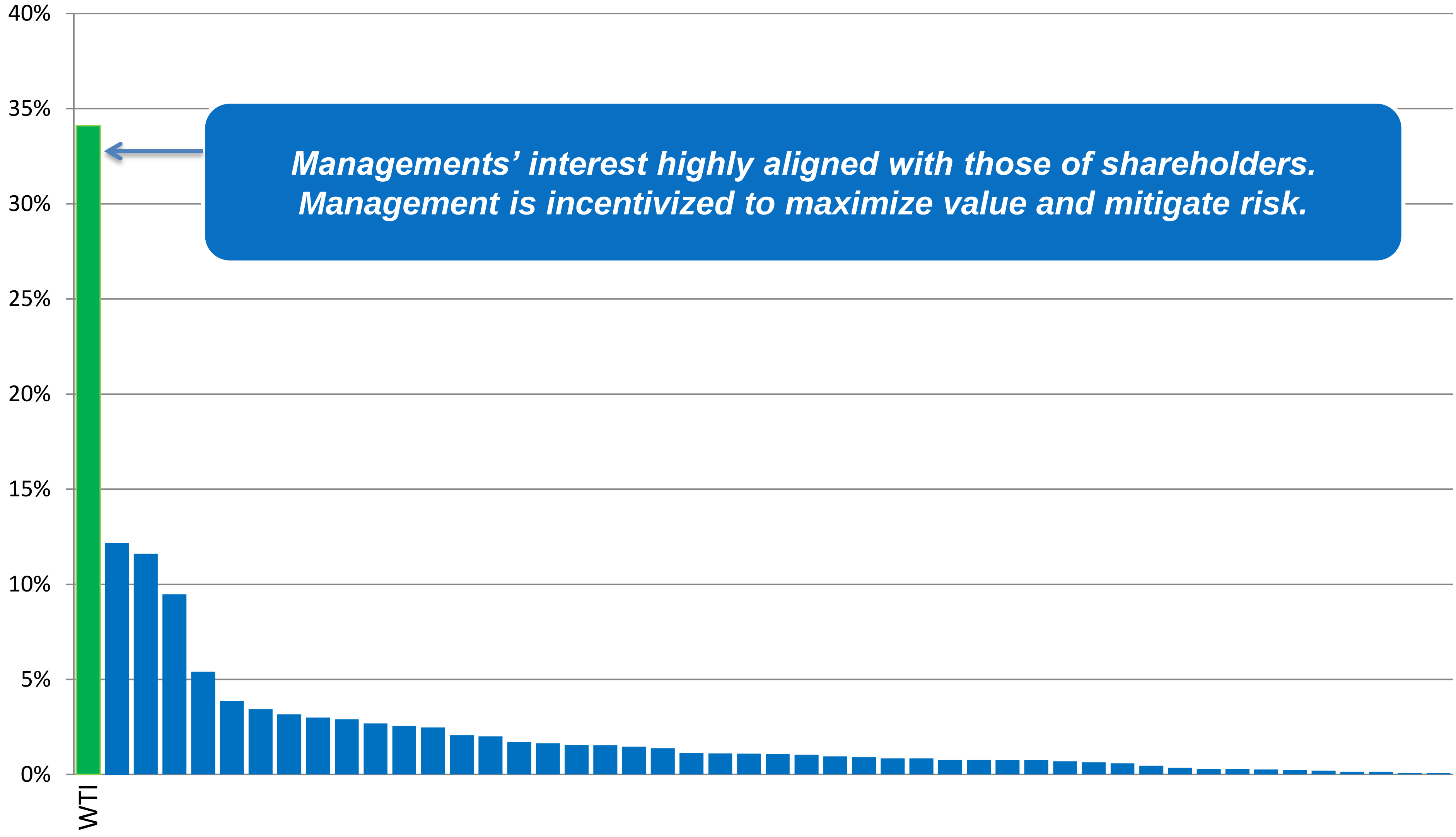
Identified Upside

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

Gulf of Mexico Provides an Attractive, Large Acquisition Opportunity Set

Financial Overview

Management Ownership[1] – Among the Highest of Public E&P Companies[2]



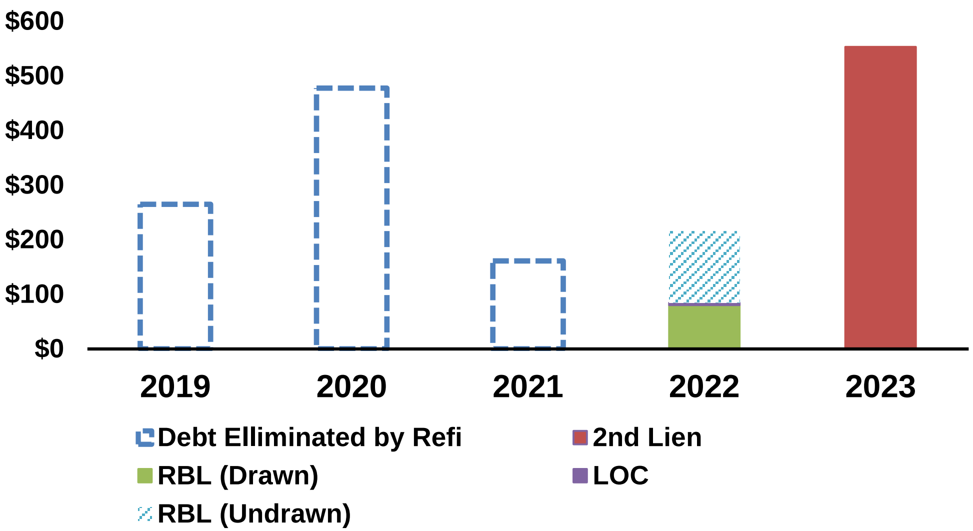
1) Ownership percentage of Named Executive Officers from 2020 company proxies, Data sources include IR Insight, Bloomberg & Company filings
2) Companies sorted alphabetically: AR, AXAS, BCEI, BRY, BTE, CDEV, CNX, COG, CPE, CPG, CRK, CXO, DVN, EQT, ERF, ESTE, GDP, GPOR, HPR, KOS, LONE, LPI, MCEP, MCF, MGY, MR, MRO, MTDR, MUR, NOG, OAS, PDCE, PE, PHX, PVAC, QEP, REI, RRC, SBOW, SD, SM, SNDE, SWN, TALO, WLL, WPX, XEC

Significantly Improved Capital Structure

Liquidity as of 09/30/20

9.75% 2nd Lien Notes due 2023	$553 MM
RBL Borrowings[1]	$ 80 MM
Total Debt [2]	**$633 MM**
Total Cash & Equivalents	$ 57 MM
Available Under RBL[3]	$130 MM
Total Liquidity	**$187 MM**

Debt Maturity Schedule ($MM)

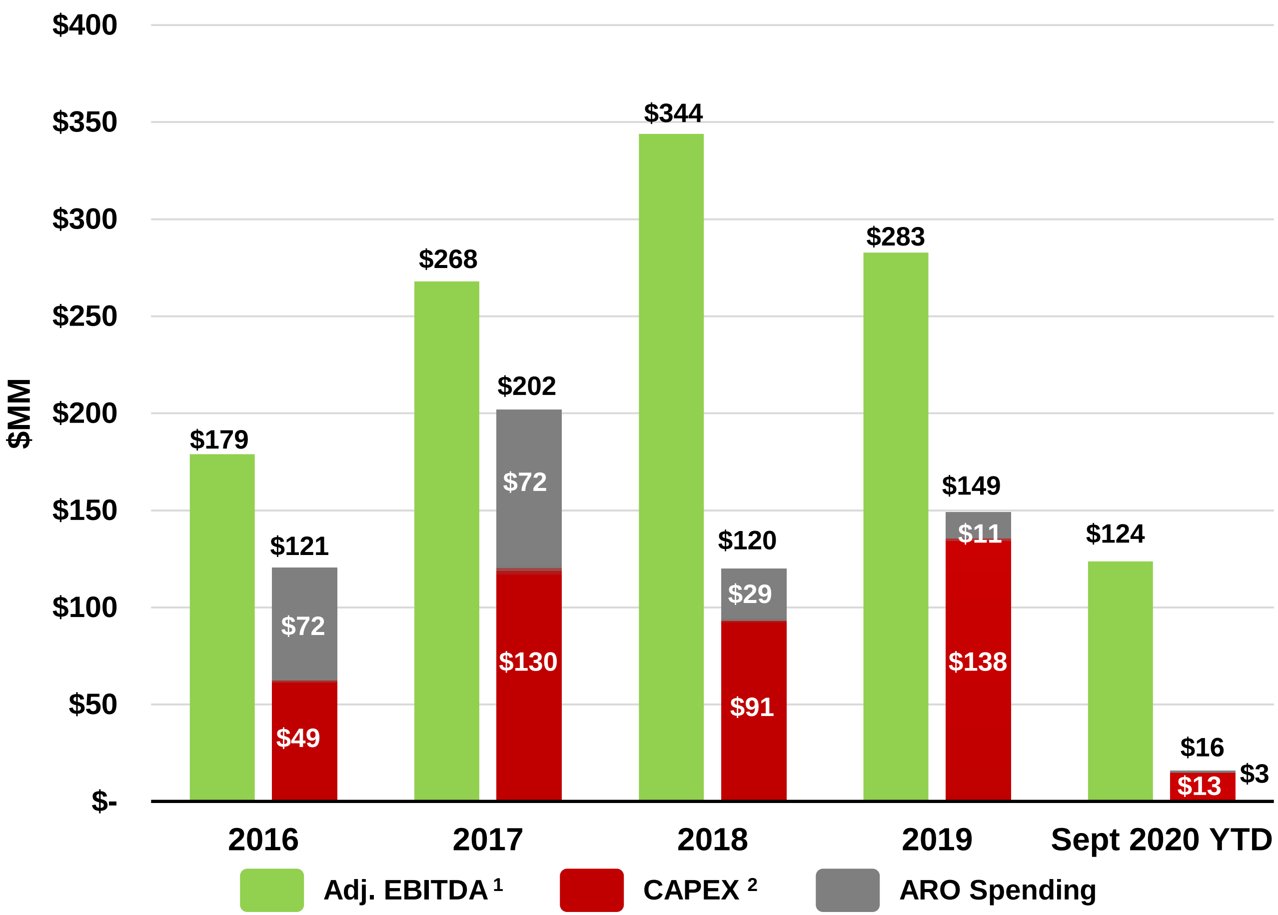


- Long-term debt reduced $97 million to $633 million from $730 million at December 31, 2019, resulting in $8 million annualized interest expense savings
- Borrowing base set at $215 million in June 2020
- Amended agreement includes manageable 1st Lien Debt to trailing twelve months EBITDA covenant thru December 2021
- Next regularly scheduled re-determination in late fall 2020

Strong Balance Sheet Provides Flexibility for Future Growth

1) RBL borrowings exclude $4.4 MM of outstanding letters of credit.
2) Excludes reduction of $7.7 MM related to debt issuance costs.
3) RBL availability reduced by $4.4 MM of outstanding letters of credit.

Generating Steady and Significant Unlevered Free Cash Flow[1]



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

Each $1 improvement in oil price increases annual Adjusted EBITDA[1] by ~$6 MM[3]
Each $0.10 improvement in gas price increases annual Adjusted EBITDA[1] by ~$5 MM[3]

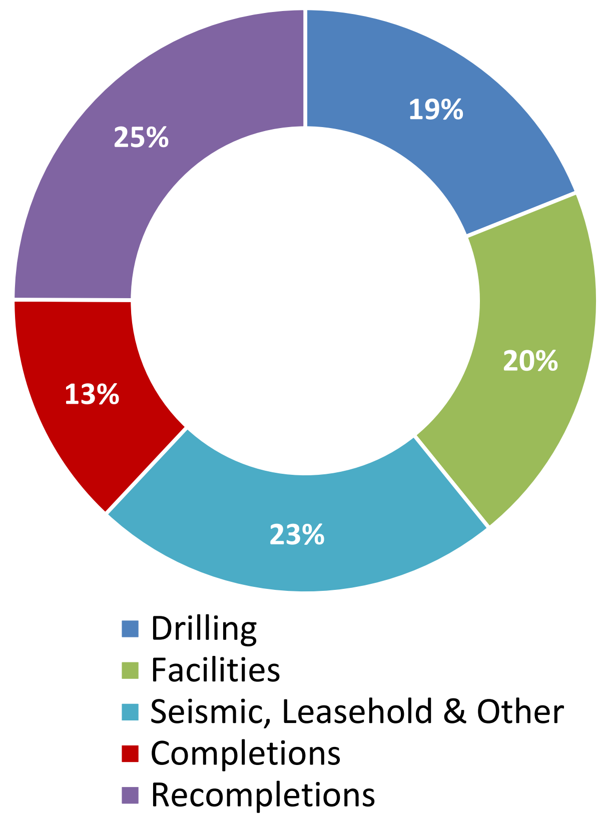
Substantial Unlevered Free Cash Flow[1] Generation Provides Optionality

1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see slide 45 for description of reconciling items to GAAP net income.
2) Excludes acquisitions; includes only accrual basis capital expenditures.
3) Before impact of hedging.

2020 Current Capital Expenditure Forecast

- Current 2020 CAPEX[1] forecast
  - \$15 - \$25 MM
- 2020 forecast CAPEX[1] is ~85% less than \$138 million spent in 2019
- Current 2020 P&A forecast
  - \$2 - \$4 MM

CAPEX Allocation[1,2]

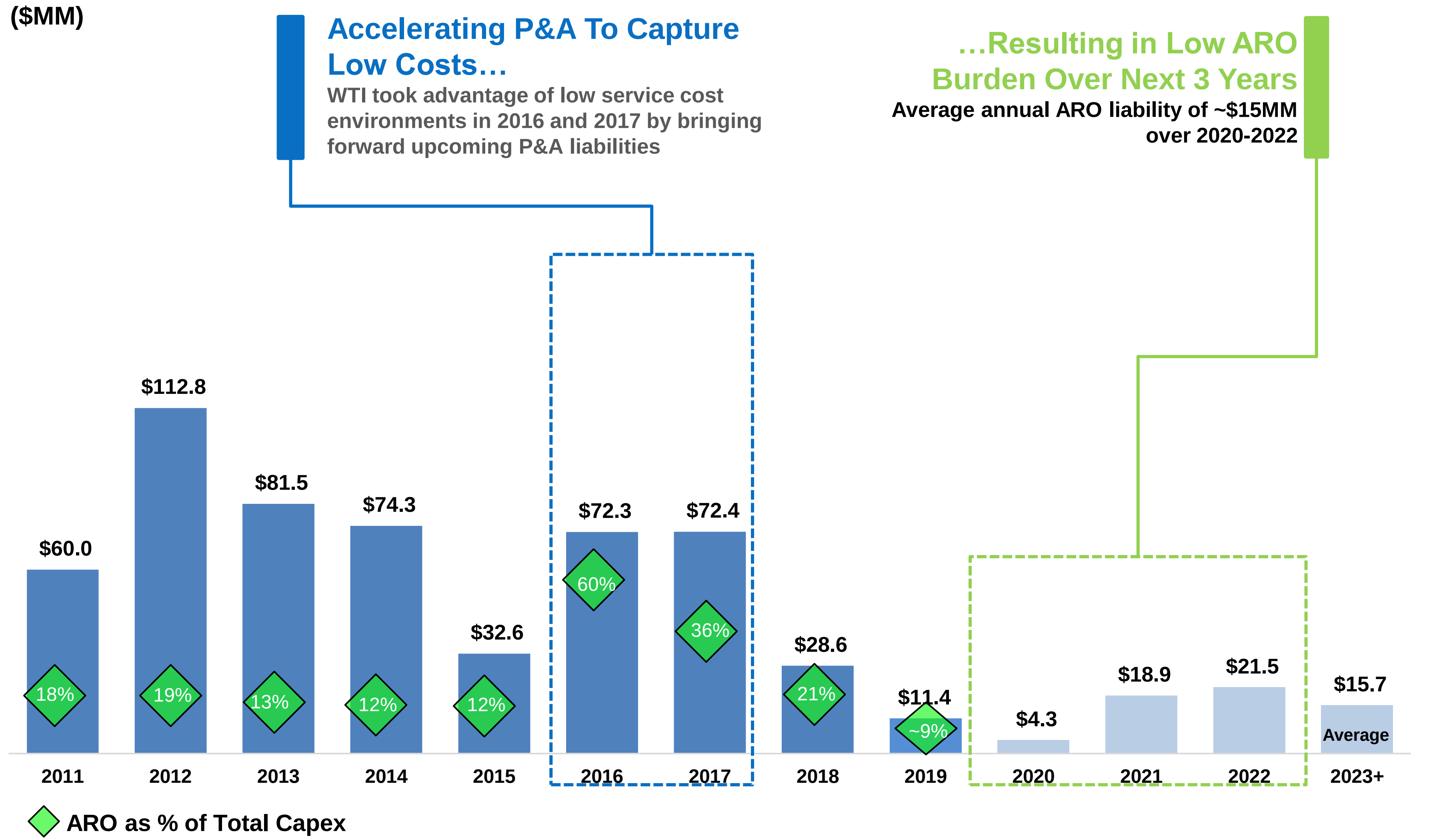


Meaningfully Reducing and Managing 2020 CAPEX to Preserve Cash Flow

1) Accrual basis capital expenditures only.
2) Based on midpoint of 2020 forecast.

Proactive Management of Asset Retirement Obligations

Undiscounted P&A Schedule[1,2]



1) Net of amounts held in escrow (total of $29.9 MM); Additional P&A liability estimate of $440 MM from 2023-2050.
2) As of year-end 2019 and includes Mobile Bay and Magnolia acquisitions.

Remaining 2020 and Beyond

- ***W&T has been able to persevere and thrive through multiple pricing downturns for ~40 years because of its strategy to focus on cash flow generation and continuously improve the profitability of its assets, at any commodity price***
- Cost reduction efforts and maintaining profitability across all fields is the key priority
- Discussions with vendors both large and small to negotiate reduced rates
- Monitor and address low margin fields
- Continue to prioritize HS&E matters to manage and maintain safe and compliant operations and back office environment
- Continue to high-grade inventory to be able to respond to commodity price improvement
- Working diligently and acting with urgency to successfully navigate through and take advantage of “once in a lifetime” opportunities created by the perfect storm of unprecedented macro challenges

Continually Monitor and Respond in Real Time to the Volatile Commodity Price Environment with Definitive Actions to Maintain Financial Flexibility, Protect Cash Flow and Preserve Future Value

Investment Highlights

Focused on Free Cash Flow Generation

- Active expense management and capital allocation to high return, quick payback projects allowed W&T to generate $62 MM of Free Cash Flow[1] Sep YTD 2020
- Adjusted EBITDA[1] for Sep YTD 2020 was $123.7 MM
- Reduced 2020 Budget to ~$20 million due to lower prices to maximize financial flexibility
- Inventory of lower risk/higher return projects, plus upside opportunities

High Quality Asset Base with Substantial Low-Risk Upside

- Leveraging expertise of technical teams, combined with innovations to add value to existing assets
- ~$1.1 B of probable and possible reserve upside related to proved reserves with no additional capital required
- Better seismic data is leading to better decisions and enhanced recoveries
- Projects include high rate of return stacked-pay development with exploration components in very large known reservoirs

Reducing Costs to Improve Margins and Increase ROCE

- Optimizing operations has reduced LOE per Boe and D&C costs
- Attractive acquisitions, platform drilling, subsea tiebacks to existing infrastructure and high-quality assets led to 3-year reserve replacement costs of $5.05/Boe
- Surplus equipment and services in GOM allows for improved terms that significantly lowers drilling, development and asset retirement costs

Maintaining Good Liquidity and Paying Down Debt

- ~$187 MM in liquidity as of September 30, 2020
- Reduced total long-term debt by $97.5 million since December 31, 2019, resulting in approximately $8 million of annual interest expense savings
- No long-term debt maturities until 2022
- Strong balance sheet provides flexibility for the future

1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see slide 45 for a reconciliation to GAAP net income.

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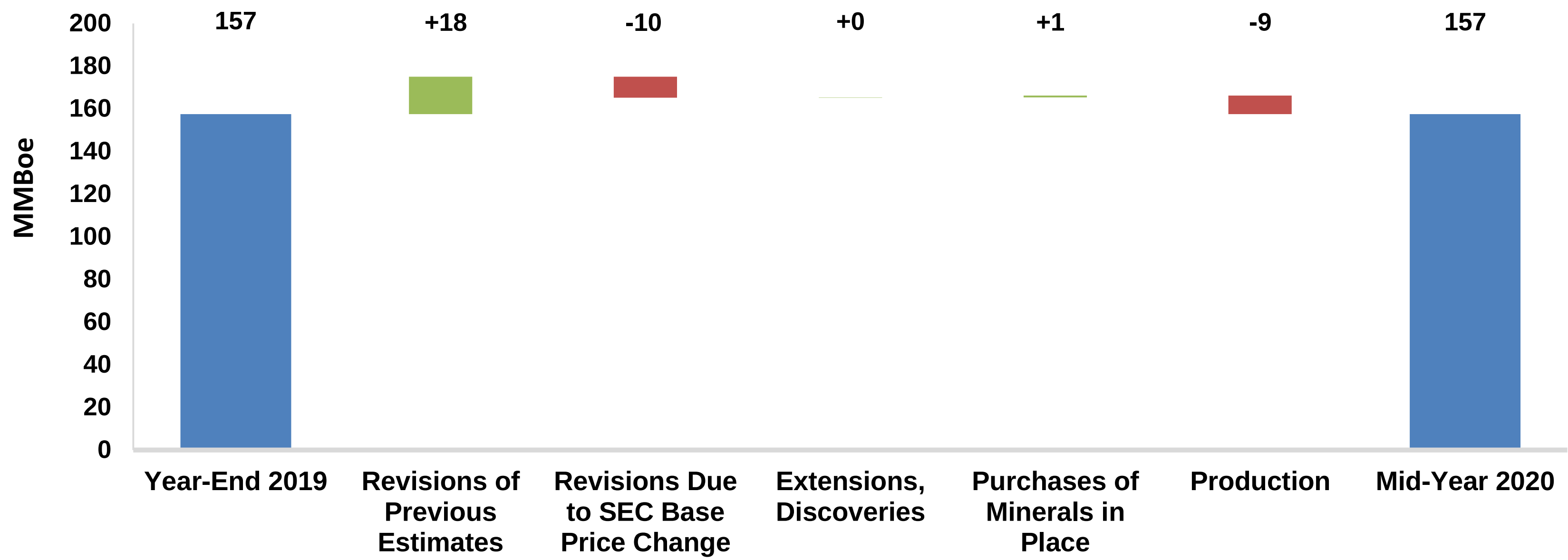
Appendix

Mid-Year 2020 Reserves Summary[1]



- 232.0 MMBoe Net Proved + Probable (2P) Reserves
- Includes Mobile Bay and Magnolia acquisitions
- All-in Reserve Replacement Cost: 2019: $4.18 per Boe; 3-year average: $5.05 per Boe
- Maintains reserve life index[2] at 10.6 years

Replaced ~100% of First Half 2020 Production with Net Positive Revisions and Acquisitions

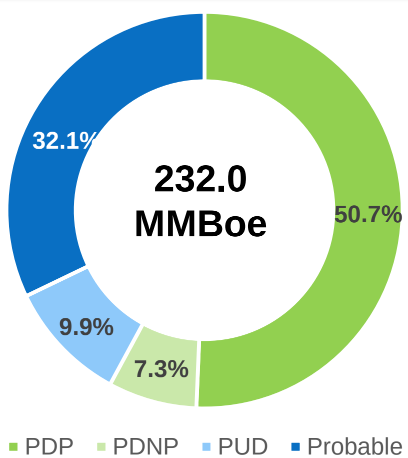
1) Based on Mid-Year 2020 reserve report by NSAI at SEC pricing of $47.37/BO and $2.07/Mmbtu; Computation may not foot due to rounding.
2) Mid-Year 2020 Proved Reserves divided by 2019 production

Reserves Summary: Mid-Year 2020 Reserve Report[1]

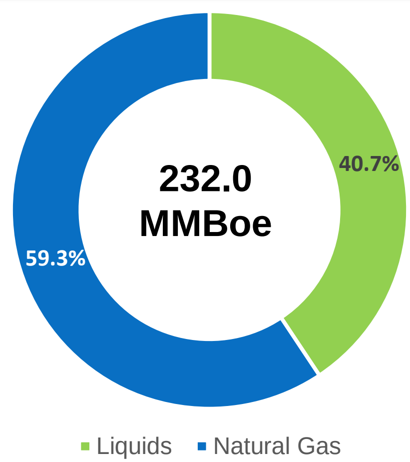
Current Reserve Report Overview[1]

Reserve Category	Total (MMBoe)	% Liquids	Pre-Tax PV-10%[2]
Proved Developed Producing (PDP)	117.5	28.3%	$671.2
Proved Developed Non-Producing (PDNP)	16.8	47.0%	194.5
Proved Undeveloped (PUD)	23.1	52.6%	160.3
Total 1P Reserves (Excluding ARO)	**157.4**	**33.9%**	**$1,026.0**
Total 2P Reserves (Excluding ARO)	**232.0**	**40.7%**	**$1,758.6**
1P Asset Retirement Obligations (ARO)			(173.6)
Total 1P Reserves (Reduced By 1P ARO)	**157.4**	**33.9%**	**$852.4**
Total 2P Reserves (Reduced By 1P ARO)	**232.0**	**40.7%**	**$1,585.0**

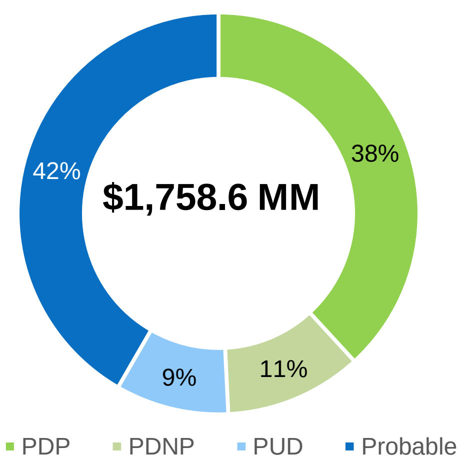
2P Reserves[1]



2P Reserves[1]



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



1) Mid-Year 2020 Reserve Report prepared by NSAI at SEC pricing.
2) Pre-Tax PV-10% is a non-GAAP measure; see reconciliation on slide 47.
3) Pre-Tax PV-10% excluding 1P Asset Retirement Obligation.

Hedging Strategy Protects Cash Flow Without Limiting Upside

Crude Oil Hedges as of November 30, 2020

Production Period	Instrument	Avg. Daily Volumes	Weighted Avg Swap Price	Weighted Avg Put Price	Weighted Avg Call Price
Crude Oil - WTI NYMEX:		(bbls)	(per Bbl)	(per Bbl)	(per Bbl)
Nov 2020 - Dec 2020	Costless Collars	1,000		$45.00	$63.60
Nov 2020 - Dec 2020	Costless Collars	9,000		$45.00	$63.50
Nov 2020 - Dec 2020	Calls (long)	10,000			$67.50
Jan 2021 - Dec 2021	Swaps	1,000	$41.00		
Jan 2021 - Dec 2021	Swaps	1,000	$42.05		
Jan 2021 - Dec 2021	Swaps	1,000	$42.18		
Jan 2021 - Dec 2021	Swaps	1,000	$43.00		
Jan 2022 - Feb 2022	Swaps	1,000	$42.75		
Jan 2022 - Feb 2022	Swaps	1,000	$42.80		
Jan 2022 - Feb 2022	Swaps	1,000	$43.40		
Mar 2022 - May 2022	Swaps	1,000	$41.90		
Mar 2022 - Mar 2022	Swaps	1,076	$42.75		
Apr 2022 - Apr 2022	Swaps	1,055	$42.75		
May 2022 - May 2022	Swaps	1,000	$42.75		
Jan 2021 - Jan 2021	Costless Collars	2,895		$35.00	$50.00
Feb 2021 - Feb 2021	Costless Collars	3,340		$35.00	$50.00
Mar 2021 - Mar 2021	Costless Collars	2,382		$35.00	$50.00
Apr 2021 - Apr 2021	Costless Collars	2,362		$35.00	$50.00
May 2021 - May 2021	Costless Collars	1,944		$35.00	$50.00
Jun 2021 - Jun 2021	Costless Collars	1,924		$35.00	$50.00
Jul 2021 - Jul 2021	Costless Collars	1,525		$35.00	$50.00
Aug 2021 - Aug 2021	Costless Collars	1,346		$35.00	$50.00
Sep 2021 - Sep 2021	Costless Collars	1,350		$35.00	$50.00
Oct 2021 - Oct 2021	Costless Collars	1,012		$35.00	$50.00
Nov 2021 - Nov 2021	Costless Collars	948		$35.00	$50.00
Dec 2021 - Dec 2021	Costless Collars	625		$35.00	$50.00
Jan 2022 - Jan 2022	Costless Collars	1,473		$35.00	$50.00
Feb 2022 - Feb 2022	Costless Collars	1,790		$35.00	$50.00
Mar 2022 - May 2022	Costless Collars	1,000		$35.00	$47.50
Mar 2022 - May 2022	Costless Collars	1,000		$35.00	$49.50

W&T's Hedging Positions Lock in Floor Price, Protect Future Cash Flows and Allow Opportunity to Capture Potential Price Increases

Hedging Strategy Protects Cash Flow Without Limiting Upside

Natural Gas Hedges as of November 30, 2020

Production Period	Instrument	Avg. Daily Volumes	Weighted Avg Swap Price	Weighted Avg Put Price	Weighted Avg Call Price
Natural Gas - Henry Hub NYMEX:		(MMBTU)	(per MMBTU)	(per MMBTU)	(per MMBTU)
Nov 2020 - Dec 2022	Calls (long)	40,000			$3.00
Nov 2020 - Dec 2022	Costless Collars	40,000		$1.83	$3.00
Nov 2020 - Dec 2020	Costless Collars	10,000		$1.75	$2.58
Nov 2020 - Dec 2020	Swaps	10,000	$2.03		
Nov 2020 - Dec 2020	Swaps	15,000	$2.21		
Jan 2021 - Dec 2021	Costless Collars	20,000		$2.17	$3.00
Jan 2021 - Dec 2021	Swaps	10,000	$2.62		
Jan 2021 - Dec 2021	Costless Collars	10,000		$2.20	$3.00
Jan 2022 - Feb 2022	Costless Collars	30,000		$2.20	$4.50
Mar 2022 - May 2022	Costless Collars	10,000		$2.25	$3.40
Jan 2022 - Jan 2022	Swaps	20,000	$2.79		
Feb 2022 - Feb 2022	Swaps	30,000	$2.79		
Mar 2022 - Mar 2022	Swaps	10,095	$2.69		
Apr 2022 - Apr 2022	Swaps	11,571	$2.69		
May 2022 - May 2022	Swaps	10,000	$2.69		

W&T's Hedging Positions Lock in Floor Price, Protect Future Cash Flows and Allow Opportunity to Capture Potential Price Increases

Fourth Quarter 2020 Guidance (As of December 8, 2020)

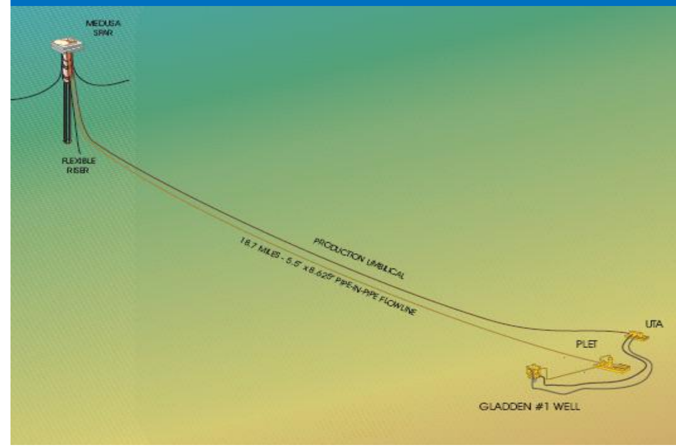
Oil (MMBbls)	1.1 - 1.2
NGL's (MMBbls)	0.35 - 0.37
Natural Gas (BCF)	10.5 – 11.1
Total (MMBoe)	3.2 – 3.4
Total (Boed/d)	34,700 – 36,900
Lease Operating Expenses	$43.0 - $48.0 MM
G & T and Production Taxes	$5.4 - $5.9 MM
G & A	$11.7 - $12.9 MM
Current Income Tax Expense Rate	0%

Significant Infrastructure Advantage

W&T Owns Substantial Infrastructure in the Gulf of Mexico

Platform Rig on infield production facility (EW 910 Area)

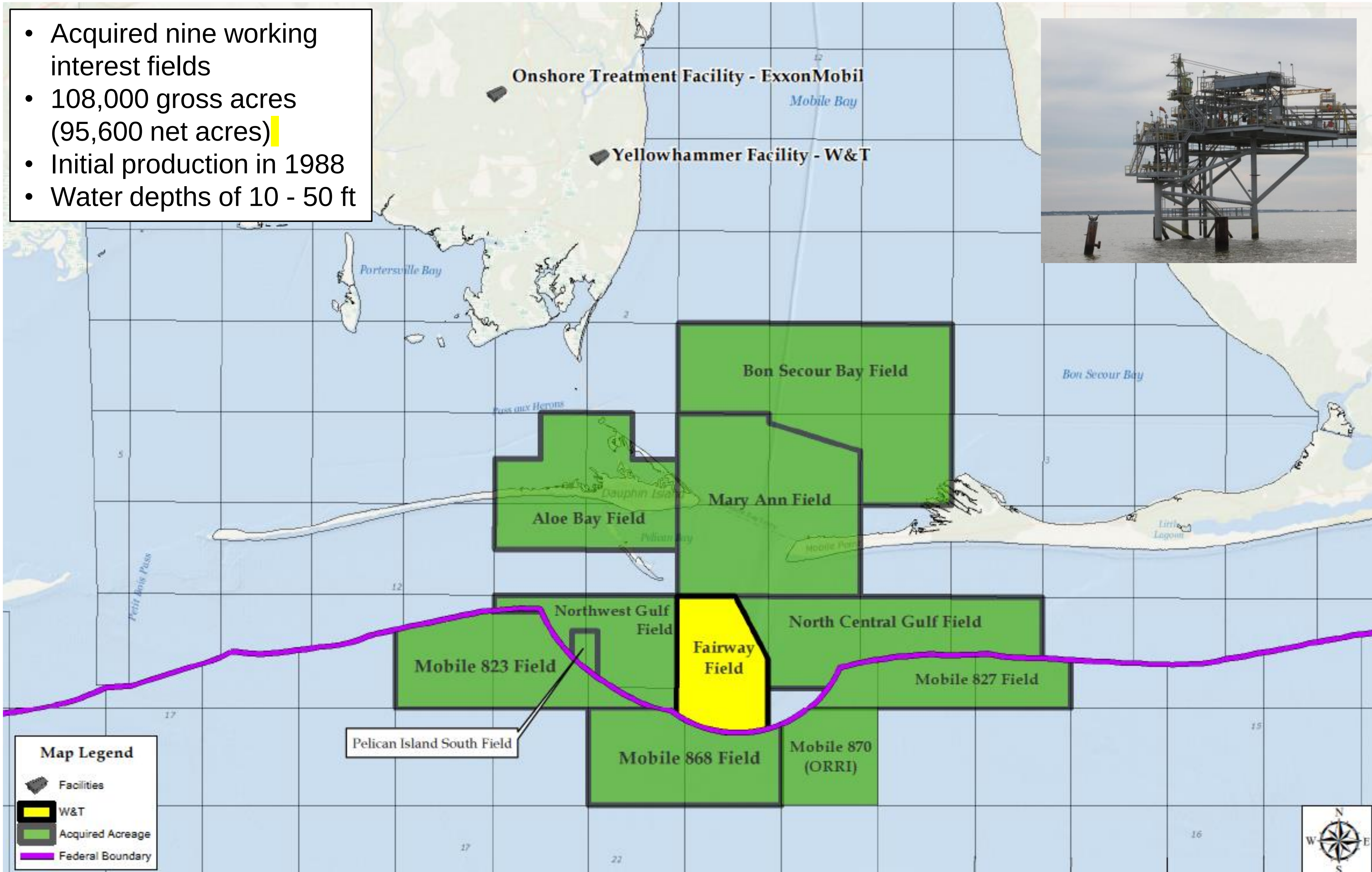
Subsea tieback to existing infrastructure (MC 800 Gladden)



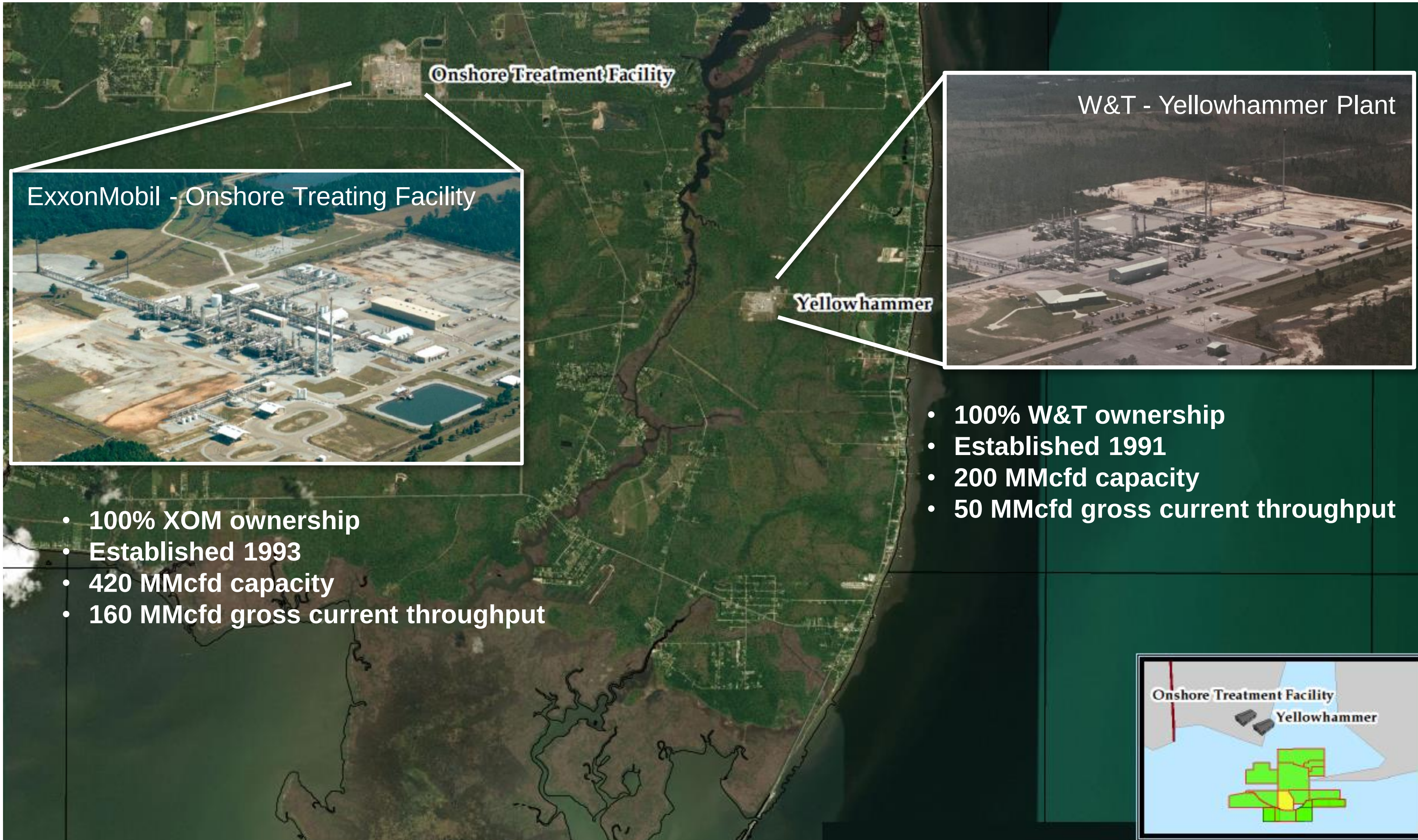
- **147 existing structures provide a key advantage when evaluating/developing prospect opportunities**
- **Economic Advantage**
  - *Reduces capital expenditures*
  - *Increases returns by generating cashflow quicker*
  - *Marketing contracts already in place*
  - *Provides revenue upside in potential Production Handling Agreements (PHA)*
    - *2018 $13.4 MM, 2019 $15.3 MM, September YTD $7.7 MM*

Mobile Bay Acquisition – XOM Producing Fields

- Acquired nine working interest fields
- 108,000 gross acres (95,600 net acres)
- Initial production in 1988
- Water depths of 10 - 50 ft



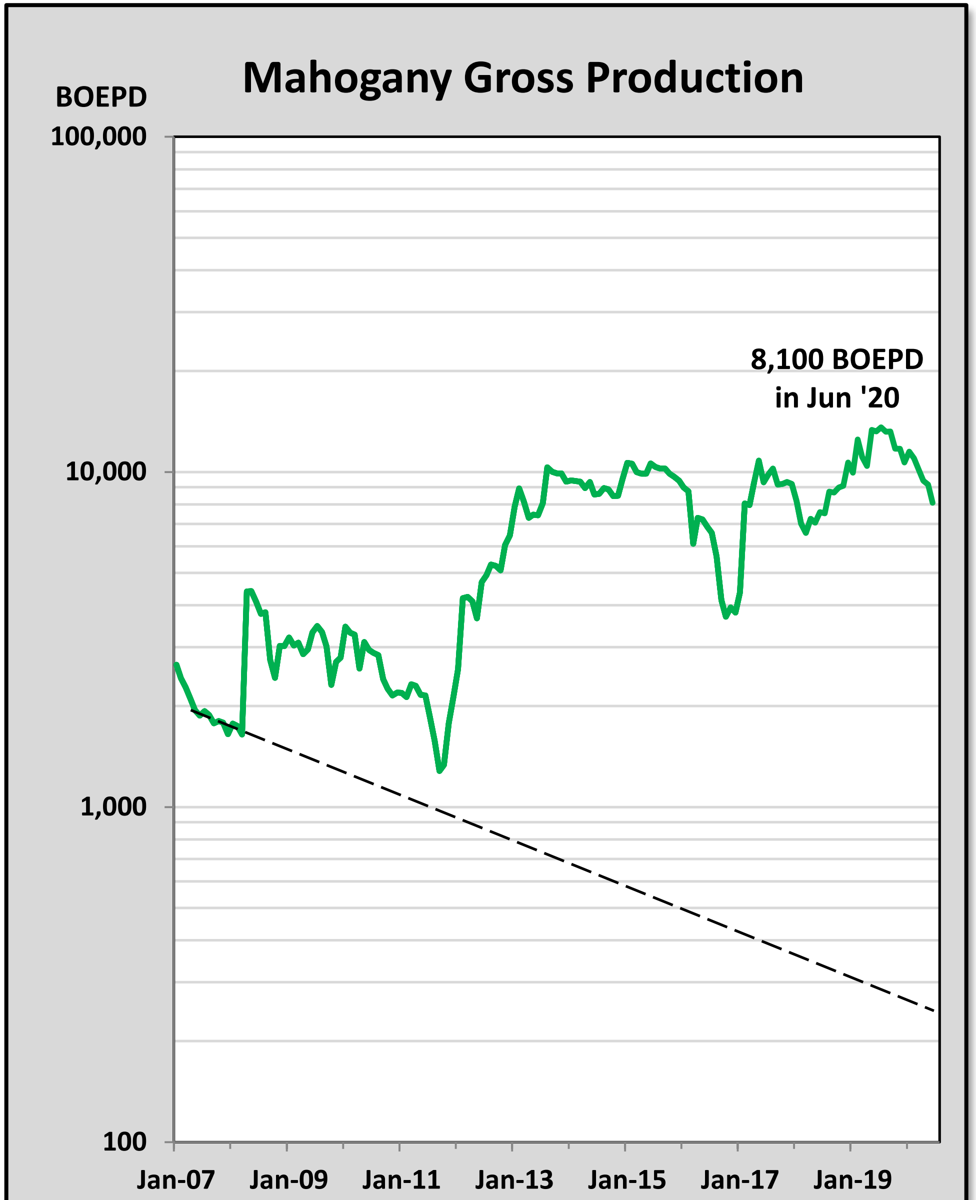
Mobile Bay Acquisition – Onshore Gas Treating Facilities



- 100% XOM ownership
- Established 1993
- 420 MMcfd capacity
- 160 MMcfd gross current throughput

- 100% W&T ownership
- Established 1991
- 200 MMcfd capacity
- 50 MMcfd gross current throughput

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)
- Originally purchased Amoco's interest in 2000
- Purchased additional interest in 2004 & 2008
- Cumulative purchase price of $175MM
- Total Net Cash Flow (including capex) from final purchase date[1] = $572 MM

Have increased value by:

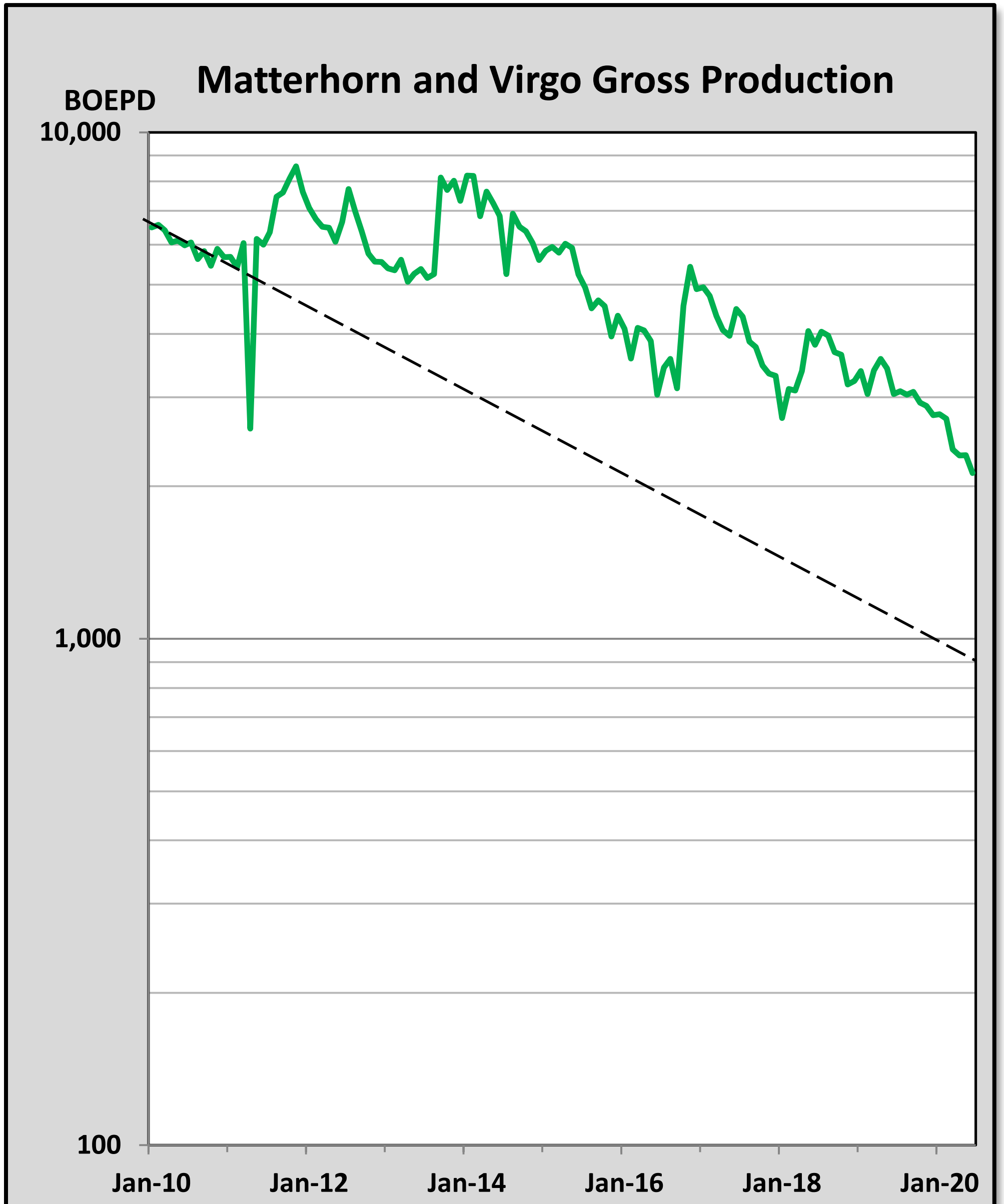
- Development and exploration drilling
- Performing recompletes
- Reworks and performance optimization

Current Reserves[2]

1P Reserves:	27.8	MMBoe
2P Reserves:	52.0	MMBoe
3P Reserves:	107.8	MMBoe

1) As of June 30, 2020.
2) As determined by Netherland Sewell & Associates as of June 30, 2020 based on SEC pricing.

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
- $115MM acquisition cost
- Total Net Cash Flow (including capex) from final purchase date[1] = $501 MM

Have increased value by:

- Drilling sidetracks
- Performing recompletes
- Instituting waterflood
- Entering processing arrangement ($58 million in processing revenues received to date)

Current Reserves[2]

1P Reserves:	5.7	MMBoe
2P Reserves:	10.6	MMBoe
3P Reserves:	19.4	MMBoe

1) As of June 30, 2020.
2) As determined by Netherland Sewell & Associates as of June 30, 2020 based on SEC pricing.

Continued Sub-Salt Exploration and Development Success

SS 349 "Mahogany" (WI: 100%, NRI 83.3%)[1]

- Substantially expanded the size and depth of the field since 2011 by drilling/sidetracking 13 new producing locations
- Stacked pay sands: At least six pay zones proven to be productive in field
  - *Historically, main pay has been the P-Sand*
  - *In 2013, A-14 well logged over 370' of net oil pay in five zones & discovered the deep T-Sand. The T-Sand has currently produced over 9 MMBO and 17 BCF from 3 wells.*
  - *In 2016, A-18 well logged oil pay beneath the T-Sand in the 'U' Sand*
  - *In 2018, A-17 well, A-5 sidetrack and A-19 wells placed on production*
  - *In 1Q 2019, recompleted A-6 and acid stimulated A-18 wells*
  - *Successfully completed the A-6 S/T targeting the P-Sand and placed online in 4Q2019*
- Significantly increased field production rate since 2011
- Quality inventory of future drilling projects
  - *Exploiting reservoirs in P, Q, and T thru V - Sands*
  - *Extending reservoir limits both in depth and aerially*
  - *Legacy 3D seismic reprocessing completed in Q2 2020 and new 3D survey obtained in Q3 2020, field re-interpretation underway*
  - *Rig demobed in 2019 to save cost while evaluating seismic*

Mahogany Platform

Additional Benefits:
- ✓ Proven success in the field
- ✓ Low risk projects
- ✓ Spread rig costs over more projects
- ✓ Add production from low-cost recompletion projects

1) Except A-5 sidetrack: 30% WI currently.

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 Income", "Adjusted EBITDA" and "Free Cash Flow". Management uses these non-GAAP financial measures in its analysis of performance. In addition, Adjusted EBITDA is a key metric used to determine the Company's incentive compensation awards. 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 EBITDA and to 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, and gain on debt transactions. W&T believes the presentation of Adjusted EBITDA provides useful information regarding its ability to service debt and to fund capital expenditures. The Company 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. W&T's management believes that Free Cash Flow is an important financial measure for use in evaluating the Company's financial performance and measures the Company's ability to generate cash from business operations in excess of its capital spending and debt servicing requirements. Free Cash Flow, as W&T calculates it, may not be comparable to Free Cash Flow measures reported by other companies.

These measures are widely used by investors and research analysts for the valuation, comparison, rating and investment recommendations of companies. The following table presents a reconciliation of W&T's net (loss) income to Adjusted EBITDA and to Free Cash Flow

	Three Months Ended			Nine Months Ended	
	September 30,	June 30,	September 30,	September 30,	
	2020	2020	2019	2020	2019
			(In thousands) (Unaudited)		
Net (loss) income	$ (13,339)	$ (5,904)	$ 75,899	$ 46,737	$ 64,527
Interest expense, net	14,135	14,816	14,445	46,061	42,934
Income tax benefit	(21,057)	(8,736)	(55,500)	(23,294)	(67,023)
Depreciation, depletion, amortization and accretion	25,127	29,483	38,841	93,736	110,680
Unrealized commodity derivative loss (gain)	13,112	37,992	(5,670)	(1,416)	40,951
Amortization of derivative premium	1,483	3,407	3,931	9,239	11,664
Bad debt reserve	(1)	47	55	82	193
Gain on debt transactions	-	(28,968)	-	(47,469)	-
Adjusted EBITDA	$ 19,460	$ 42,137	$ 72,001	$ 123,676	$ 203,926
Capital expenditures (1)	1,184	(4,596)	(39,187)	(13,024)	(106,083)
Plug and abandonment	(624)	(1,915)	(5,099)	(2,788)	(7,740)
Interest expense, net	(14,135)	(14,816)	(14,445)	(46,061)	(42,934)
Free Cash Flow	$ 5,885	$ 20,810	$ 13,270	$ 61,803	$ 47,169

1) On an accrual basis and includes purchases of furniture, fixtures and other

Non-GAAP Reconciliations

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, and gain on debt transactions. 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, 2020	June 30, 2020	September 30, 2019	September 30, 2020	September 30, 2019
	(In thousands, except per share amounts) (Unaudited)				
Net (loss) income	$ (13,339)	$ (5,904)	$ 75,899	$ 46,737	$ 64,527
Unrealized commodity derivative loss (gain)	13,112	37,992	(5,670)	(1,416)	40,951
Amortization of derivative premium	1,483	3,407	3,931	9,239	11,664
Bad debt reserve	(1)	47	55	82	193
Deferred tax benefit	(21,170)	(8,736)	(55,764)	(23,407)	(55,764)
Gain on debt transactions	-	(28,968)	-	(47,469)	-
Adjusted Net (Loss) Income	$ (19,915)	$ (2,162)	$ 18,451	$ (16,234)	$ 61,571
Basic and diluted adjusted (loss) earnings per common share	$ (0.14)	$ (0.02)	$ 0.13	$ (0.11)	$ 0.43

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, 2019
Present value of estimated future net revenues (PV-10) ………………………………………………………	$	1,303
Present value of estimated ARO, discounted at 10% ………………………………………………………	$	(184.9)
PV-10 after ARO ………………………………………………………………………………………	$	1,117.6
Future income taxes, discounted at 10% ………………………………………………………………	$	(130.7)
Standardized measure of discounted future net cash flows[1]………………………………………………..	$	986.9

		June 30, 2020
Present value of estimated future net revenues (PV-10) ………………………………………………………	$	1,026
Present value of estimated ARO, discounted at 10% ………………………………………………………	$	(173.6)
PV-10 after ARO ………………………………………………………………………………………	$	852.4

1) Company calculates Standardized measure of discounted future net cash flows annually for 10-K filing.

W&T OFFSHORE

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