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Industry

Is the Deepwater Dead?

Date
13 October 2016

North America
United States

Industrials
Integrated Oil

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F.I.T.T. for investors

Are There Signs of Hope on Deepwater's Horizon?

The Reports of Its Death Have Been Greatly Exaggerated

Once the dominant driver of oil growth and capital budgets, the collapse in crude price and rise of US shale have led to the market pronouncing the deepwater as uncompetitive and largely dead (or at least on life support). While acknowledging significant challenges, some of them structural, we believe the industry will prove more resilient than believed, with a rising call on conventional growth into 2020 and greater cost deflation/efficiency gains than realized allowing high-quality resource to be broadly competitive - even with much of US shale. Positive APC (upgrade to BUY), CVX, RDS, KOS, CIE.

Deutsche Bank Securities Inc.

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It better not be dead, because we're going to need it

Although US onshore production and modest OPEC growth appear sufficient to meet demand growth in the near-term, we see a "call" on conventional, Non-OPEC supply (assuming annual US onshore growth of ~500Mb/d), of ~2.0 MMb/d by 2020. With deepwater representing ~16% of non-US shale oil growth barrels from 2000-2014, and higher cost oil sands representing another 11.5%, the market opportunity/need remains significant.

Marky Mark-ing to market cost and efficiency gains: More competitive than you think

Contrary to popular belief, the US onshore isn't the only sector seeing meaningful cost deflation and/or efficiency gains. While the ~60% reduction in DW rig rates has grabbed headlines, broad improvements, including drill-days (-30%-40%), steel costs (-30%), and various SURF/topsides costs (-10%-30%) have reduced total project costs by 30%-40%, in our view. And given the lag in response time, excess capacity and a moderate pick-up in activity, we expect cost and efficiency gains to be more durable than in the US onshore.

But not all barrels are created equal; Only high quality resource can compete

While all deepwater tends to get lumped together, the range of economics across projects is diverse (sub $30/bbl-$80+/bbl breakevens), with only high-quality resource set to compete. We examine various drivers of project economics, many poorly understood, including fiscal terms, resource size, resource density, and proximity to infrastructure, and potential impact. We see high quality, pre-FID deepwater projects breaking even at roughly $40-$50/bbl.

Meaningful challenges remain

Though more competitive than the market believes, meaningful challenges will continue to drive an increasing share of discretionary capital to US shale, including: geologic risk, project execution risk, geopolitical risk, and capital inflexibility. Adjustments to development strategies and scope can mitigate some risk, and large, diverse IOC budgets will invest across the spectrum, but failure to evolve would demand a higher rate of return, with an increase to 15% required IRR (vs. 10%) increasing average breakevens by $7.5/bbl.

APC, CVX, RDS and KOS are set to benefit

With many exiting the DW, fewer players than ever compete for opportunities – which should eventually benefit those still involved. We upgrade APC from Hold to Buy, where a unique strategy continues to add value, and high-return tieback inventory trails only RDS. CVX, RDS have strong pre-FID portfolio optionality, advantaged positions in leading basins, US GoM and Brazil, while KOS and CIE offer catalyst rich/special situation-driven, attractive risk-rewards

Top picks	
ExxonMobil (XOM.N),USD87.13	Hold
Anadarko Petroleum (APC.N),USD63.93	Hold

Source: Deutsche Bank

Sector valuation and risks

Companies in our integrated/large-cap space are valued on either on an EV/DACF multiple (CVX, XOM, COP, and OXY) or on a blended NAV, EV/DACF multiple methodology. NAVs assume $70/bbl, $65/bbl, and $3.75/mcf for Brent, WTI and Henry Hub pricing respectively. Primary downside risks include a decline in global oil demand and a decrease in the underlying commodity. Upside risks include increased demand and increased operator efficiency.

Table Of Contents

Executive Summary

Re-examining the supposed "death" of the deepwater

Once the dominant driver of oil growth and capital budgets, the collapse in crude price and rise of US shale have led to much of the investor universe pronouncing the deepwater as uncompetitive and largely dead (or at least on life support). While acknowledging significant challenges, some of them structural, we believe the industry will prove more resilient than believed, with a rising call on conventional growth into 2020 and greater cost deflation/efficiency gains than realized allowing high-quality resource to be broadly competitive - even with much of US shale. Positive APC (upgrade to BUY), CVX, RDS

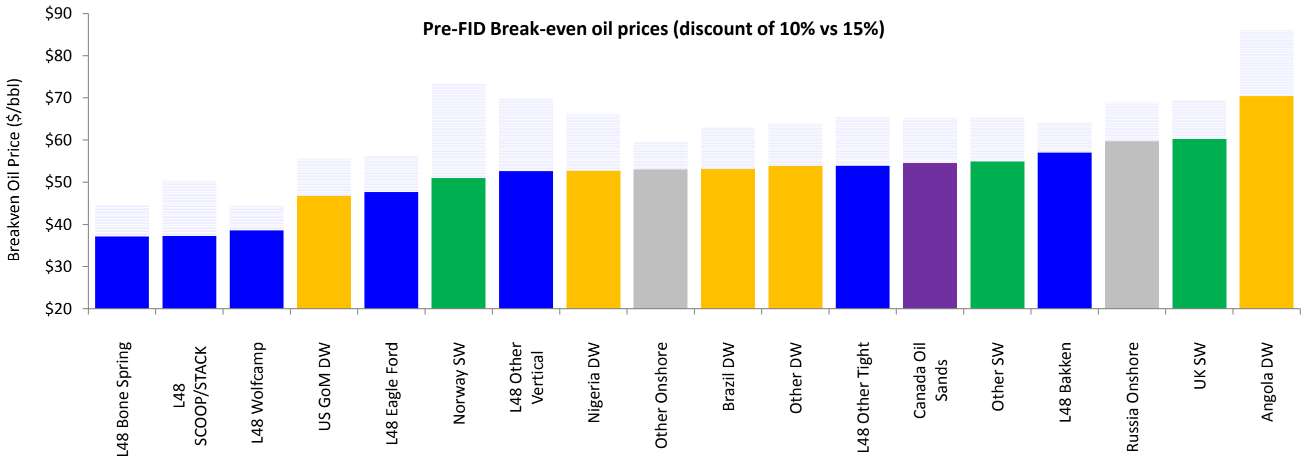
Do we need the deepwater?

Yes. Despite the overwhelming focus on US shale (and generally deservedly so…), the size of Non-OPEC (ex-US onshore) base production is ~40 mmb/d, with an underlying decline of ~3%-4%/yr (1250 Mb/d) that needs to be replaced. In our base scenario, assuming annual US onshore production growth of ~500 Mb/d per year, the "call" on conventional Non-OPEC supply would be roughly 500 Mb/d of new growth per year. With the deepwater representing ~16% of non US-shale oil growth since 2000, and likely still advantaged relative to other large sources (ie. oil sands), we expect the deepwater to remain a very important piece of global crude supply growth.

Addressing the myths

- **Myth #1: US onshore is the only place seeing meaningful cost deflation and efficiency gains**. Impressive cost deflation and efficiency gains in the US onshore have certainly been more rapid than offshore improvements. However, we believe that cost deflation and efficiency gains are much more significant than the market appreciates. We estimate that total project development costs will decline 30%-40% from 2014 levels by 2017, efficiency gains are underappreciated (drill days reduced 30%-50% since 2013/2014), and innovations and adjustments to development strategies (standardization, scope reduction, phased developments), will reduce full-cycle costs more than the market appreciates. *Further, we expect that cost savings are likely to be much more durable than in the US onshore*.
- **Myth #2: Deepwater economics can't compete**. Based on cost and efficiency gains, we believe that *high-quality* deepwater projects will breakeven in the $40-$50/bbl range, comparable to much of current US onshore inventory.

Figure 1: And while the deepwater will likely remain structurally challenged vs. the US onshore, DW project economics stack-up well vs. other conventional and unconventional (oil sands) supply sources



Source: Deutsche Bank

- **Myth #3: All of the "easy oil" is gone.** Technical challenges have certainly increased (average water depth/measured depth of offshore wells has increased from 135m/3300 to 800m/4300m over the last 20 years), but this has been the case for 150 years. Technology continues to move resource from "cutting edge" to "mainstream", with contractor/market supply/demand a larger driver of cost than technological creep.

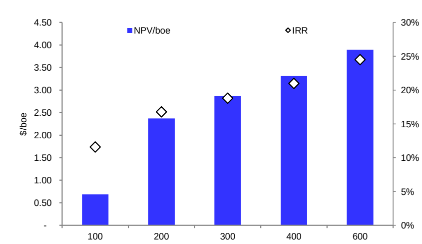
Not all barrels are created equal

Although we expect the deepwater to remain relevant and competitive (albeit in moderation), clearly not all projects will pass global muster. While the differentiating factors are complex and varied, we see the following as key (and poorly understood) drivers of project economics.

- **Fiscal Terms** – Even if the subsurface is identical, fiscal terms can make or break a project. We see a range of $NPV/boe of ~$1.00/boe to $7.50/boe at $60/bbl crude, with US GoM (attractive terms/stability) and recent/emerging regimes (Guyana, Morocco, Ghana, etc) offering an attractive foundation. Look for adjustments to current fiscal terms as an opportunity to increase competitiveness (ie. Angola, Brazil).

- **Resource Size**. Size matters, and bigger is generally better due to ability to spread large fixed costs across a higher resource base. We see F&D costs reduced by up to 50% as size increases, with a potential US GoM development of 100-600 mmboe generating NPV/boe of $1.65/boe to $5.00/boe, or an IRR of 14% to 28% at $60/bbl.

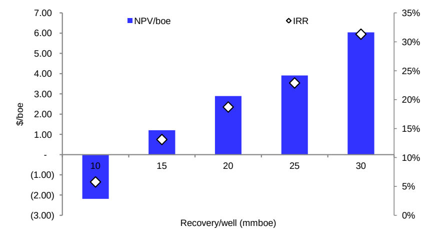
Figure 2: Bigger is better…



Source: Deutsche Bank

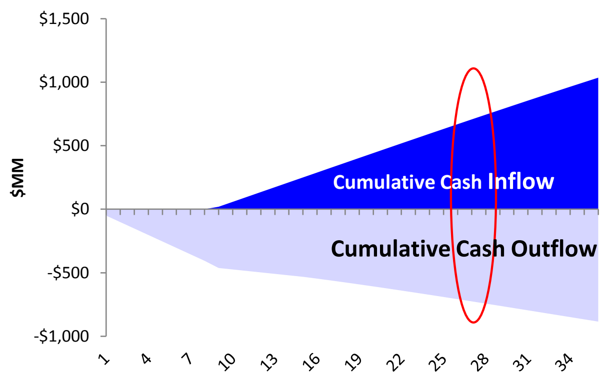
- **Resource density/well deliverability**. Possibly the least understood by investors; refers to both 1) recovery per well, and 2) resource concentration (proximity to planned infrastructure). With drilling and completion costs representing up to 40%-60% of total project cost, a doubling of recovery/well can triple NPV/boe and double project IRR, while reduced subsea infrastructure can improve returns 30%-50%.
- **Proximity to Infrastructure**. A potential offset to resource size, proximity to existing infrastructure can offer potentially dramatic cost savings, particularly in well-developed basins such as the US GoM and the North Sea. Given constrained capital budgets in the medium-term, and an increased shift towards short to mid-cycle capital, we expect tie-back opportunities, with potentially comparable payback periods to onshore pad drilling, to be increasingly important over the next 3-5 years. **RDS, APC, STL** and **CVX** show the largest estimated backlogs.

Figure 3: Less wells, higher returns



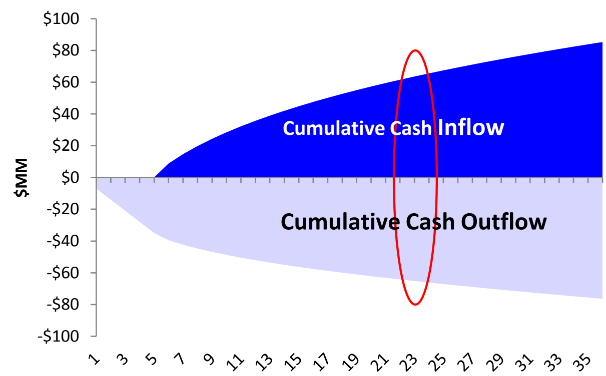
Source: Deutsche Bank

Figure 4: Subsea tiebacks offer a competitive capital allocation alternative to the Lower 48 onshore - We est a payback period of ~29 mo for a 2-well GoM Tieback



Source: Deutsche Bank, X-axis shows months from initial investment

Figure 5: And a comparable pay period of 24 mo for a 4-Well Midland Pad –



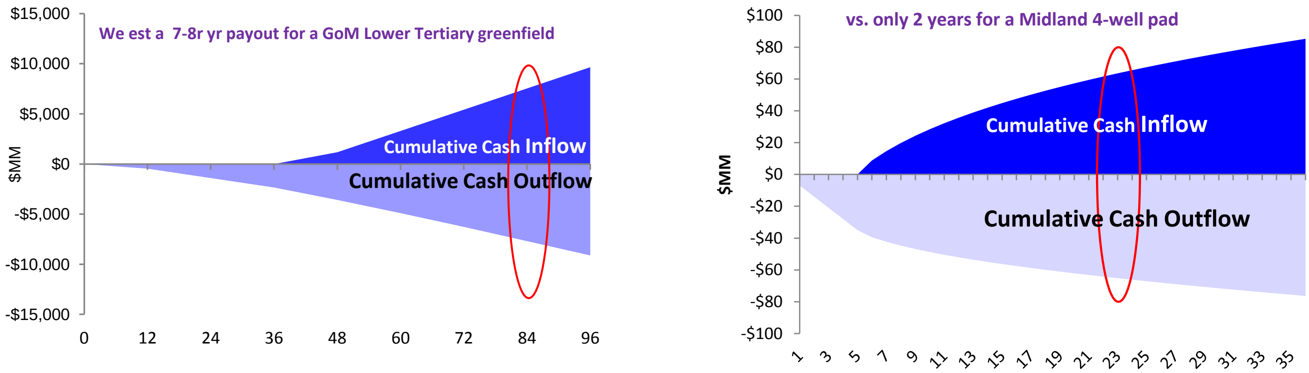
Source: Deutsche Bank, X-axis shows months from initial investment

Risks and Challenges

While reports of the death of the deepwater may be greatly exaggerated, there are significant issues, many of them structural, which will continue to challenge the industry, particularly relative to the US onshore.

- Capital inflexibility/long-cycle payback – While the sheer size of many deepwater projects allows for the generation of high absolute NPVs, project timelines allow for very little capital flexibility, with extended pay-back cycle times (DBe 7-8 yrs for Greenfield US GoM vs. ~2 yrs for Midland 4 well pad).

Figure 6: The cash-cycle/payback period for green-field DW projects is ~3-4x longer than for shale



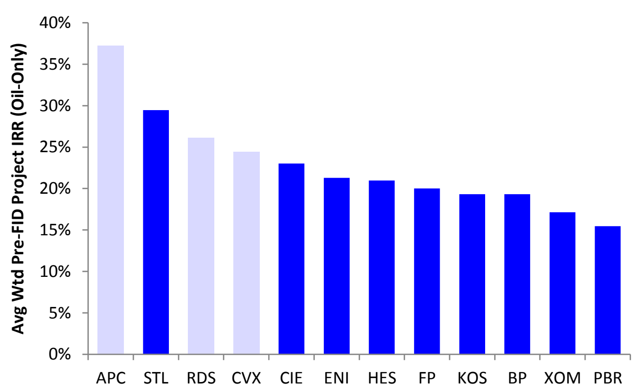
Source: Deutsche Bank, x-axis represents months from first spend

- Project Execution risk – Based on data for projects that are at least 70% complete, cost overruns for deepwater projects have ranged from 13%-20% on average, with delays of 33%/46% vs. initial timelines for subsea/floating platforms.
- Geologic/Geopolitical risk – Full-cycle returns require accounting for exploration performance, where average IRRs have been at or below 10%/15% since 2006 at $60/$80/bbl crude. Few companies have consistently added value via the drillbit. Further, potential for geopolitical instability adds risk to potential returns (eg. Nigeria).

Companies: Who is best positioned?

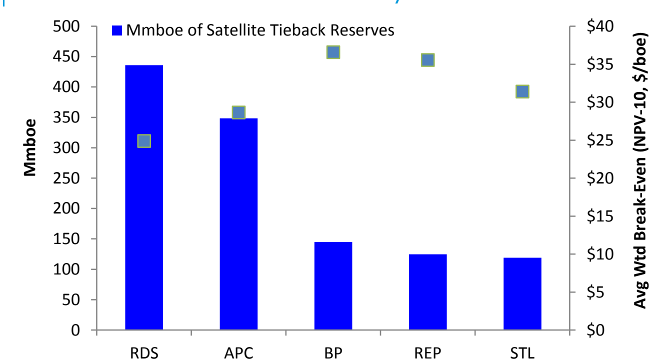
As large numbers of operators have exited the deepwater in recent years (COP, MRO, DVN, etc.), the number of players involved has consolidated considerably. Based on the depth and quality (ie. weighted average IRR of opportunity set) of deepwater portfolios and importance to 2016-2025 growth strategies (or monetization strategies, for some), we view APC, CVX, RDS, KOS and PBR as best positioned to benefit from a better than expected outlook in the deepwater. Highest leverage in our coverage is clearly at CIE, a "special situation" stock where we see attractive risk/reward, although offering a risk profile that may not be attractive for many investors.

Figure 7: Material tieback inventory (APC, RDS) & high-quality pre-FID options: APC, RDS, CVX



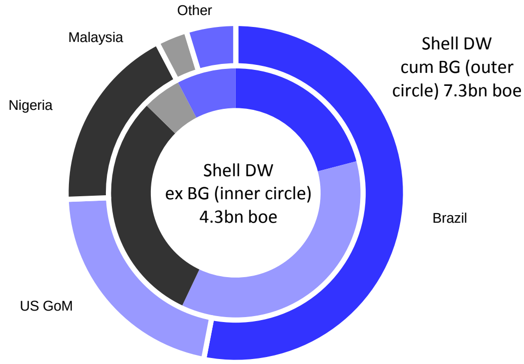
Source: Deutsche Bank, Wood Mackenzie

Figure 8: Trailing only RDS, APC boasts the largest /most attractive satellite tieback inventory in the GOM



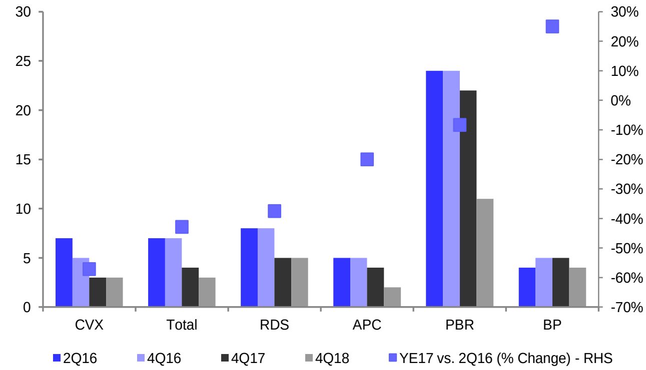
Source: Deutsche Bank, excludes under-dev and recent start-ups, reserves are net and ex in-fill drilling

Figure 9: The deepwater opportunity: Post BG c7bn boe with a weighting to high margin Brazil and US GoM



Source: Deutsche Bank, excludes underdevelopment and recent start-ups, reserves are computed on a net basis and exclude in-fill drilling opportunities

Figure 10: 60% fewer UDW rig commits by YE17; CVX is positioned to capture deflationary cost trends vs. peers



Source: Deutsche Bank, Wood Mackenzie

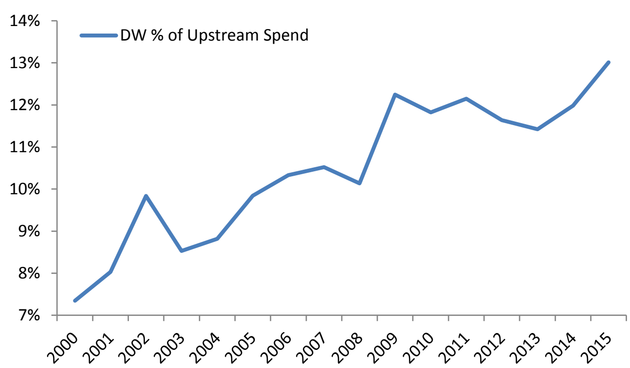
What happened?

How did we get here? A look back at trends over the past 15 years

In order to better understand the current challenges and opportunities associated with the deepwater, we look briefly at trends over the past 15 years.

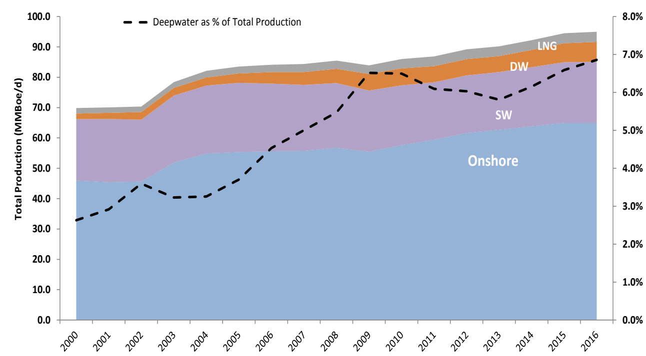
While offshore activity has played a prominent role in the industry for decades, deepwater activity accelerated significantly in the late 90's/early 2000's, driven by advances in 3D seismic, drilling/completion technologies and rising oil prices. Capital spend in the deepwater as a percentage of total E&P spend increased from 7% in 2000 to 12% by 2009. The high level of activity was further reflected in the share of new projects reaching FID, where deepwater reached a high of 13% in 2003 (or ~25% in terms of size of discovered resource across oil-weighted conventional FIDs)

Figure 11: Deepwater Spend % of Upstream Total



Source: Deutsche Bank, Wood Mackenzie

Figure 12: Deepwater Production % of Upstream Total



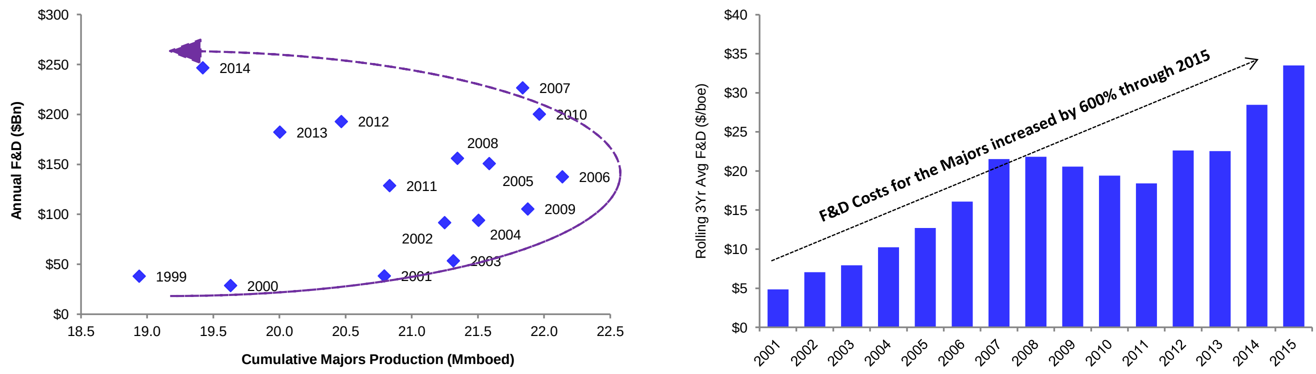
Source: Deutsche Bank, Wood Mackenzie

The significant ramp in deepwater activity, combined with an inflationary environment in broader commodity and industrial markets and increasingly technically challenging deepwater resource, led to a raft of problems, including rapid cost inflation and challenges in project execution (i.e. delays and cost overruns).

Cost Inflation

Between 2000 and 2008, average upstream (E&P) costs increased by ~175%, which along with an increased mix of longer-cycle projects (deepwater, LNG, etc.) in corporate budget allocations helped to drive a 600% increase in average finding and Development (F&D) costs for the Majors. No segment of the offshore business was immune from the rapid pace of cost inflation with deepwater rig rates increasing ~500% and FPSO hull costs increasing over 200%.

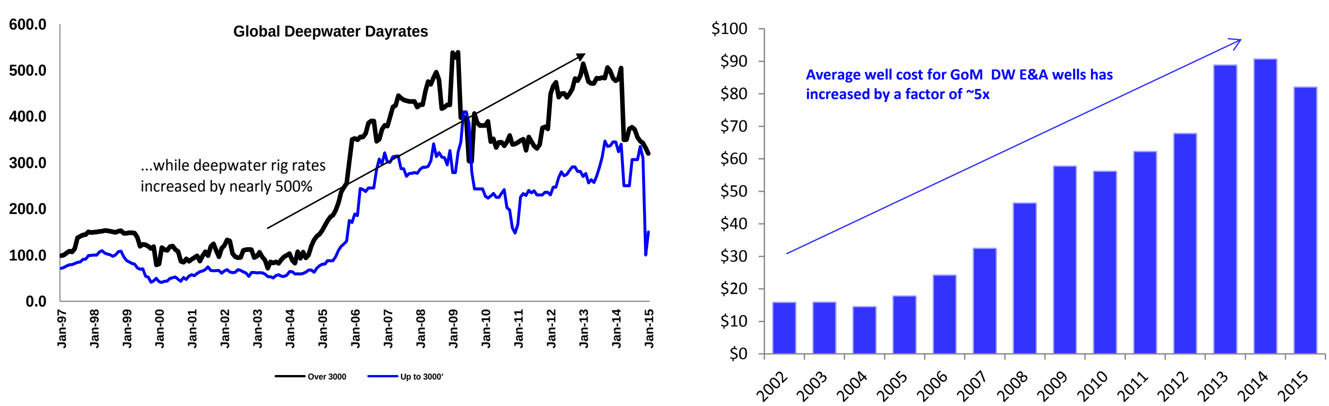
Figure 13: Majors F&D Trends 2000-2015 (More for Less?)



Source: Deutsche Bank, Wood Mackenzie, Data includes reported results from BP, COP, CVX, ENI, FP, RDS, STL, XOM; average F&D calculated on a production-weighted basis

The drivers of the massive inflation were varied, ranging from rapid inflation in raw materials (steel) to increases in technical requirements and tightness in supply/demand for everything from rigs to subsea equipment to yard capacity for FPSO hull fabrication.

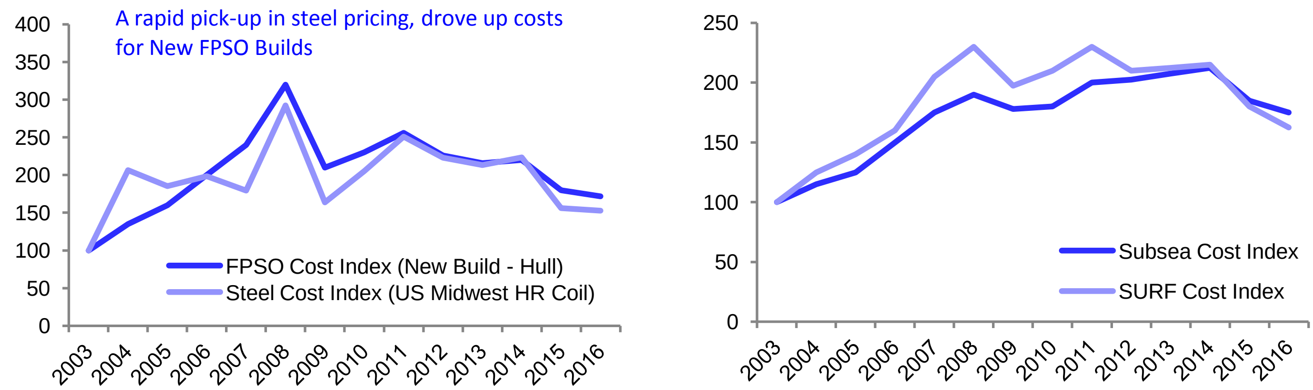
Figure 14: The industry's rapid charge into deepwater development drove a material increase in offshore project costs – the most visible of which came in the form of increased drilling costs – (day-rates increased by nearly 500%)



Source: Deutsche Bank, Bloomberg Finance LP, Wood Mackenzie

Steel prices (the dominant driver of materials/fabrication costs which represent ~80% of the costs of a new FPSO hull) saw an over 150% increase from 2003 to 2008 (see Figure 15) while subsea costs increased by a factor of over 2x for both sub-system equipment and SURF related components.

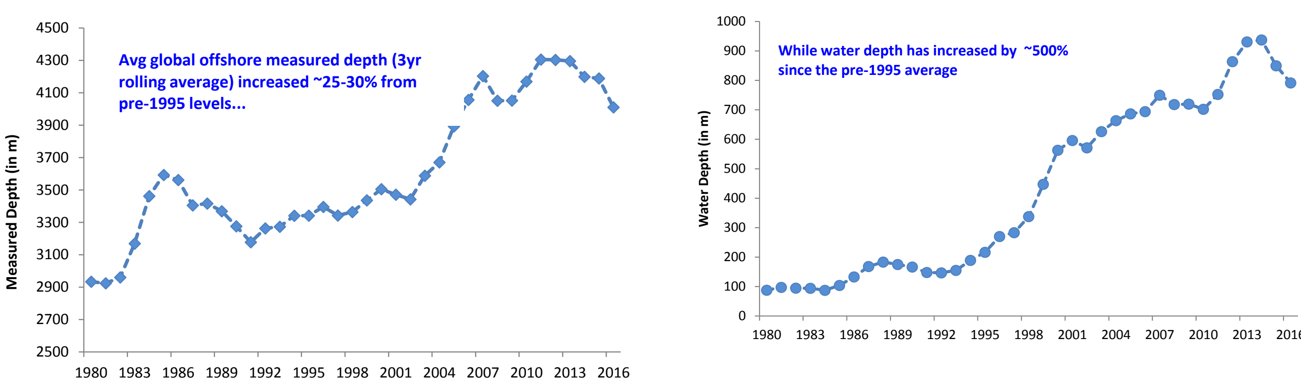
Figure 15 …And while a capacity-short deepwater market in the early/mid 2000s underpinned a rapid acceleration in drilling costs, offshore project cost escalation surfaced across several project development components



Source: Deutsche Bank, IHS

A relatively rapid increase in project complexity (global offshore measured depth/water depth increased by ~27.5%/500% from pre-1995 average levels) added an increasingly higher degree of integration of costly leading-edge/pioneering technological solutions.

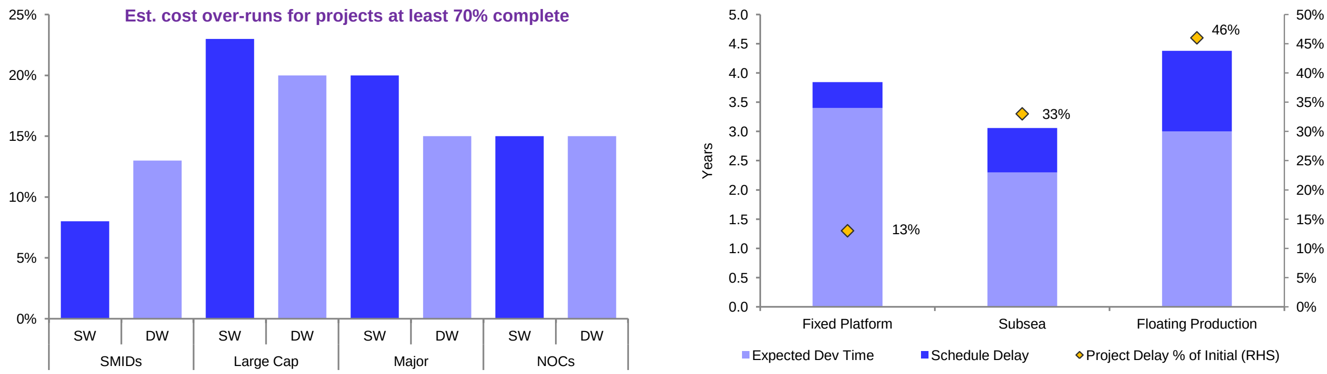
Figure 16 …While increased technology requirements also contributed to the increase in project costs…



Source: Deutsche Bank, Wood Mackenzie

Beyond the rapid cost inflation, which challenged project economics, expanded activity levels also stretched the capabilities of large producers to efficiently manage project development, resulting in increasing rates of project delay and cost overruns. Project delays and cost over-runs became more prevalent with an evolution in fiscal terms that stipulated increasingly higher local content requirements (Brazil, Nigeria). In West Africa, deep-water lead times (from discovery to first production) increased from 6-8 years between 2000-2005 to almost 10 years after 2008.

Figure 17: Execution shortcomings have resulted in project delays and cost over-runs (and deteriorating project returns) across several high-profile projects/regions

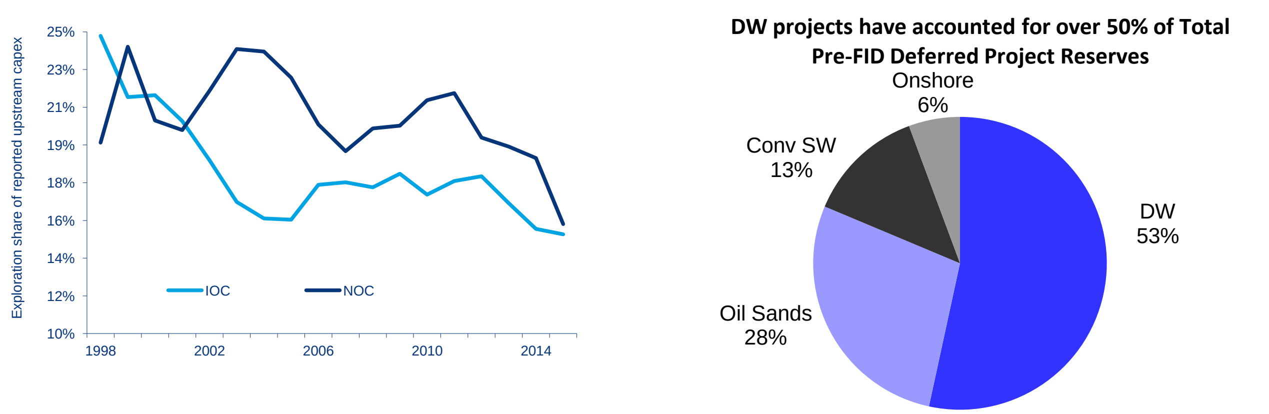


Source: Deutsche Bank, Wood Mackenzie

The end result was a dramatic decrease in deepwater development activity, with reductions in offshore rig counts and deepwater project FIDs falling from 3/yr (8.5% of project sanctions from 2001-2009) to 1/yr from 2013-2015.

Given the dramatic decline in deepwater activity, a number of operators completely exiting the deepwater business (COP, MRO), and the rise of US onshore activity, we examine the future of the industry, whether the deepwater can compete in a rapidly evolving industrial landscape, and projects and companies that are well positioned to take advantage.

Figure 18: Ultimately, the rapid collapse in oil prices in mid-2014 forced the hands of offshore operators and the industry turned its back on high-cost deep-water programs – cutting both exploration budgets and project sanctions



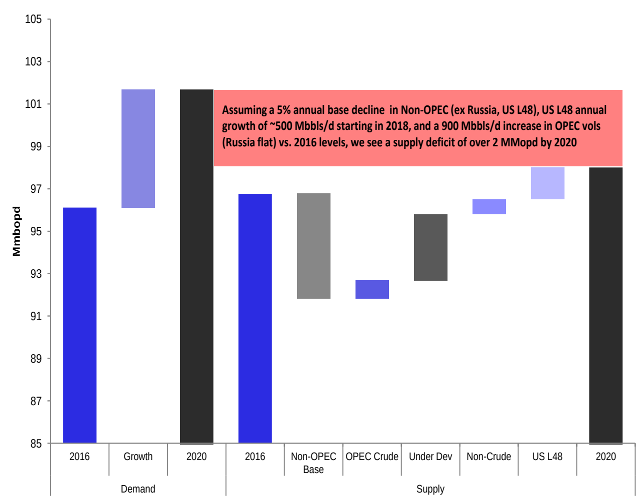
Source: Deutsche Bank, Wood Mackenzie

Do We Need DW Barrels?

With many investors concerned that deepwater (and other large, conventional projects) have been effectively pushed off of the cost curve by lower-cost onshore resource (US shale), a reasonable starting point is whether we need deepwater barrels in the first place, going forward.

Despite the overwhelming focus on US shale (and generally deservedly so…), the size of non-OPEC (ex-US onshore) base production is ~40 mmb/d. Assuming, an annual 3.5% decline in non-OPEC (Russia flat, ROW 5%), ~500 Mb/d annual growth in the US onshore (2018+), and OPEC oil production of ~34 MMb/d by 2020, we see the global oil markets potentially under-supplied by 2 MMb/d based by 2020 on DB commodity's expectation of 1.0-1.1 MMb/d product growth through 2020.

Figure 19: The Case for the DW: Addressing the long-term supply gap

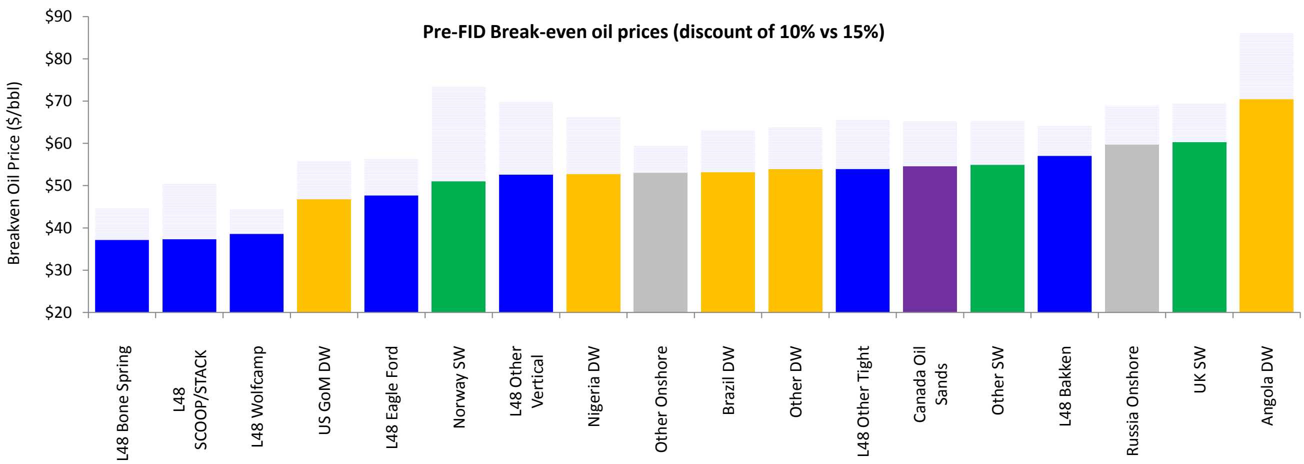


	2015	2016	2017	2018	2019	2020	Source
Total Product Demand	**94.8**	**96.1**	**97.2**	**98.3**	**99.3**	**100.4**	**DB Commodity Estimate**
YoY Growth		*1.3*	*1.1*	*1.0*	*1.1*	*1.1*	
Global Crude Supply	78.5	78.5	78.1	78.5	79.2	79.0	Various; See below
BioFuels	2.3	2.4	2.5	2.6	2.7	2.8	DB Commodity Estimate
Processing Gains	2.2	2.3	2.3	2.3	2.4	2.4	DB Commodity Estimate
NGLs, Others	13.6	13.7	13.7	13.8	13.8	13.8	Various; See below
Global Product Supply	**96.5**	**96.8**	**96.6**	**97.2**	**98.0**	**98.0**	
Supply Excess	**1.7**	**0.6**	**-0.6**	**-1.0**	**-1.3**	**-2.4**	
Crude Supply							
Recent Project Starts	0	0.9	1.3	1.7	1.8	1.7	Wood Mackenzie
Kashagan	0	0.0	0.1	0.2	0.3	0.3	Wood Mackenzie
Under Development	0	0.1	0.6	1.2	1.8	2.2	Wood Mackenzie
Non-OPEC Growth	**0.0**	**1.0**	**2.0**	**3.1**	**3.8**	**4.1**	
Total Non-OPEC Base	**46.2**	**44.4**	**43.0**	**42.3**	**41.6**	**40.9**	
Russia	10.7	10.9	10.9	10.9	10.9	10.9	Assumption
US Onshore	7.4	6.8	6.8	7.3	7.8	8.3	Assumes 500 Mbbls/d Annual Growth
Non-OPEC ex Russia, L48	**28.1**	**26.7**	**25.3**	**24.1**	**22.9**	**21.7**	
YoY Growth		*-5.0%*	*-5.0%*	*-5.0%*	*-5.0%*	*-5.0%*	*Assumption*
Total Non-OPEC	**46.2**	**45.4**	**45.0**	**45.4**	**45.4**	**45.1**	
OPEC	**32.3**	**33.1**	**33.2**	**33.1**	**33.8**	**34.0**	**DB Commodity Team**
Total Crude Supply	**78.5**	**78.5**	**78.1**	**78.5**	**79.2**	**79.0**	
NGL Supply							
Non-OPEC	6.81	6.72	6.66	6.73	6.72	6.68	DB Commodity Estimate
NGLs % of Liquids	*13%*	*13%*	*13%*	*13%*	*13%*	*13%*	*Assumption*
OPEC	6.76	6.94	7.05	7.08	7.12	7.16	DB Commodity Estimate
Total NGL Supply	**6.9**	**7.1**	**7.2**	**7.2**	**7.2**	**7.3**	

Source: Deutsche Bank, Wood Mackenzie, DB Commodity Team

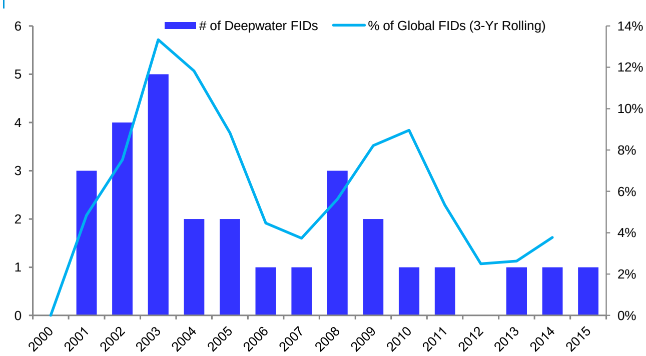
The 2 MMb/d supply gap by 2020 implies a "call" on conventional, Non-OPEC supply of roughly 500 Mb/d of new growth per year. With the deepwater representing ~16% of conventional oil growth since 2000, and likely still advantaged relative to other large sources (ie. oil sands), we expect the deepwater to remain a very important piece of global crude supply growth.

Figure 20: And while the deepwater will likely remain structurally challenged vs. the US onshore, DW project economics stack-up well vs. other conventional and unconventional (oil sands) supply sources



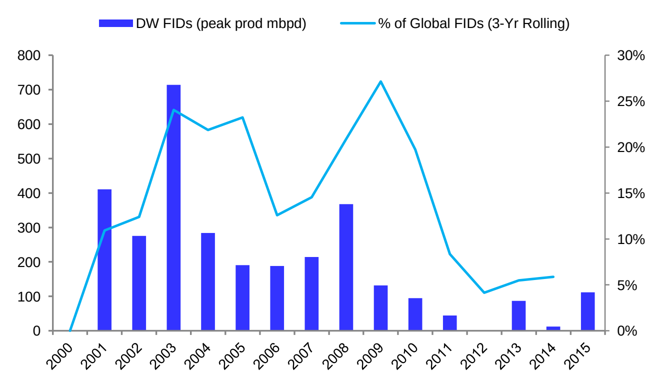
Source: Deutsche Bank

Figure 21: DW (Oil-Wtd) Project Sanctions by Yr of FID



Source: Deutsche Bank, Wood Mackenzie

Figure 22: DW (Oil-Wtd) Project Sanctions (Discovered Resource) by Yr of FID



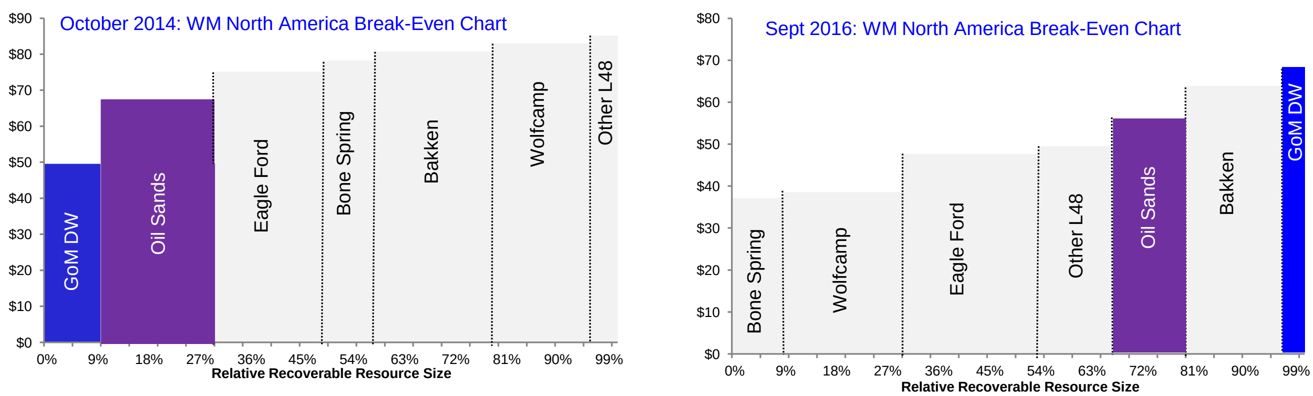
Source: Deutsche Bank, Wood Mackenzie

Addressing the myths

While the deepwater industry is not without its challenges, investors' perception of the attractiveness of the industry is often dominated by a number of myths and misconceptions, in our view, including:

1. The US onshore is the only place seeing meaningful cost deflation/efficiency gains
2. Deepwater project economics are not competitive with quality US onshore plays
3. Offshore drillers cannot support needed upstream cost deflation
4. All of the "easy oil" has been developed, and technical challenges associated with remaining deepwater oil are becoming prohibitive

Figure 23: The Evolution of US Onshore Break-Even Economics: Has the Deepwater Been Priced Out? We don't believe so



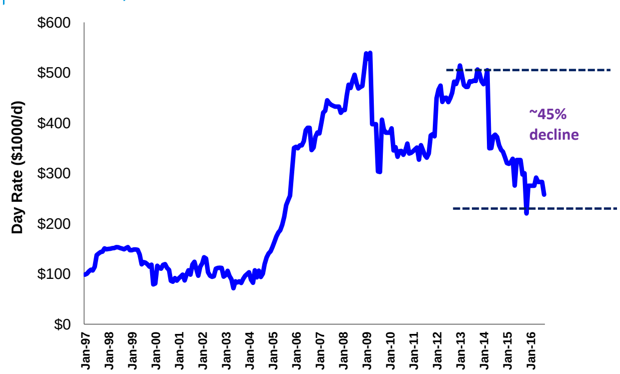
Source: Wood Mackenzie

#1 - US onshore is the only place seeing meaningful cost deflation/efficiency gains

The combination of productivity/efficiency gains and rapid cost deflation in the US onshore has seen US shale resource quickly move lower on the cost curve over the past 18-24 months, with top-tier inventory now earning an acceptable rate of return in a sub-$45/bbl environment. However, while the cost structure certainly adjusts more *rapidly* in the US onshore (and transparently), the deepwater is in the midst of an underappreciated improvement in cost structure and efficiency.

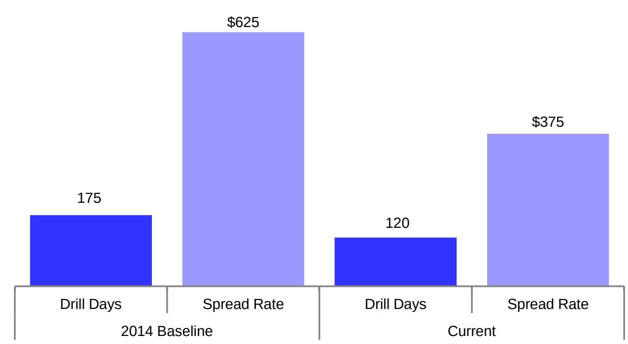
Cost deflation: Meaningful…and still going

Figure 24: Decreasing Drilling Costs: Day rates (>3000' semi-subs) have declined over 40% since 2013



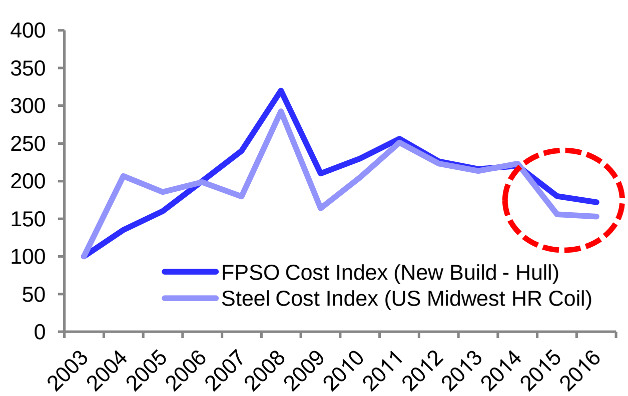
Source: Deutsche Bank

Figure 25: …..While spread rates have declined 40% since 2013/2014 (RDS GoM DW below)



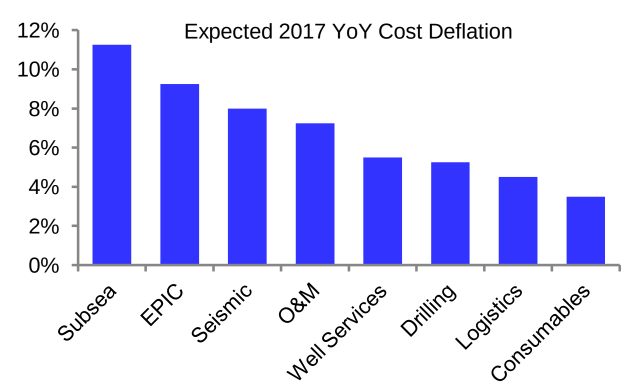
Source: Deutsche Bank, Company Data (RDS)

Figure 26: Platform cost deflation is anticipated to track the fall in steel prices….



Source: Deutsche Bank, IHS

Figure 27: …while subsea costs are still in the early stages of cost deflation



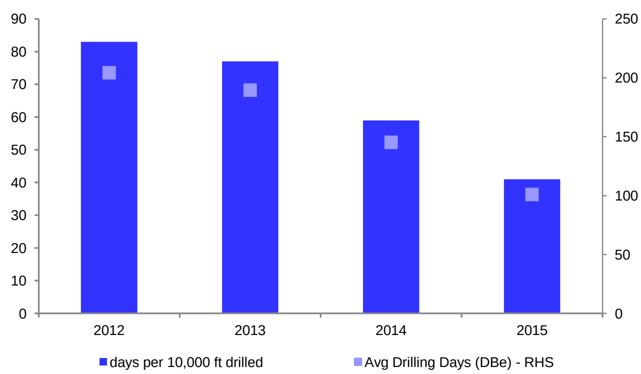
Source: Deutsche Bank, IHS

Efficiency gains: US onshore's not the only one with game

While dramatic efficiency gains in the US onshore, particularly in drilling (Bakken days spud-to-spud currently at ~14-16 days, vs. 45 days in 2011), are well known to investors, deepwater operators have also quietly seen significant gains. While improvements are ongoing across all aspects of the industry, a few trends highlight broader steps towards greater efficiency: 1) drilling efficiency (ie. days to drill), 2) standardization/simplification, and 3) re-focusing of capital towards greater efficiency opportunities (ie. tiebacks, proximity to infrastructure, etc.).

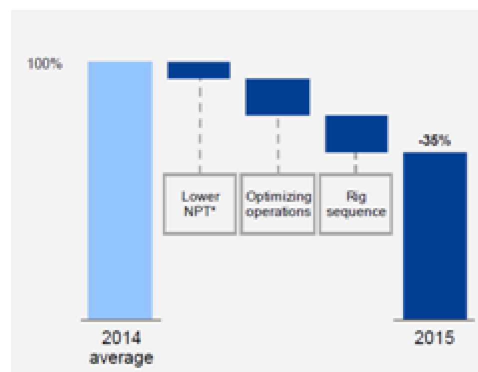
Given the smaller sample size on wells drilled and limited access to data, gains in drilling efficiency offshore have been less obvious, but no less meaningful than onshore improvements. CVX highlights a 50% reduction in days per 10,000ft drilled in the deepwater US GoM since 2012, while Shell suggests average reductions of 30%+, CIE saw reductions of 40% vs. pre-drill estimates in the US GoM, and Total saw declines of ~35% at Dalia in Angola vs. 2014.

Figure 28: Chevron has reported a ~50% reduction in days per 10,000 ft drilled in the GOM DW since 2012...



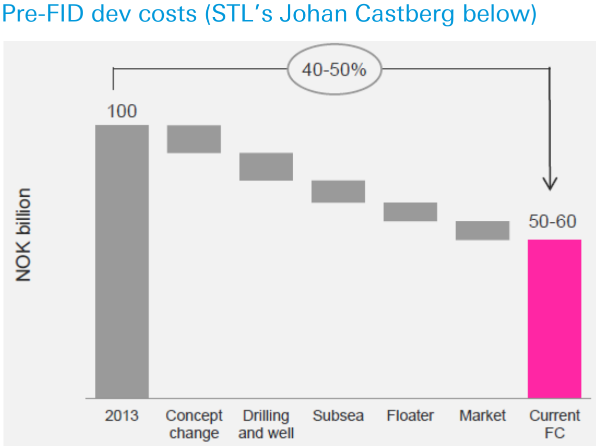
Source: Deutsche Bank, Company Presentation

Figure 29: ...And Total has decreased drilling time per well in Dalia, Angola by ~35% since 2014



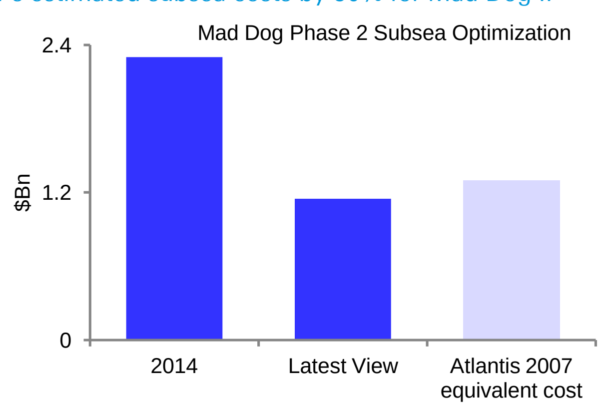
Source: Deutsche Bank, Company Presentation

Figure 30: Concept selection has also driven a reduction in Pre-FID dev costs (STL's Johan Castberg below)



Source: Deutsche Bank, Company Presentation

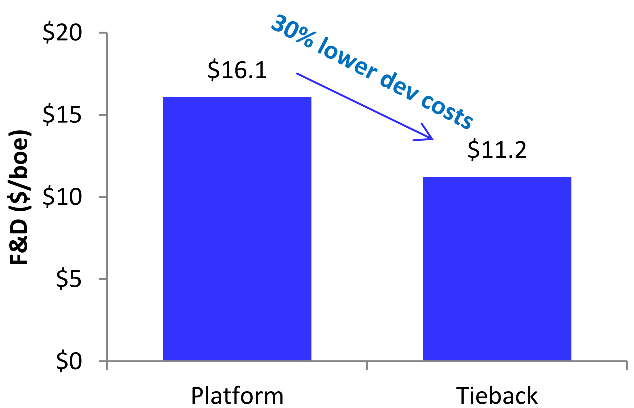
Figure 31: While development optimization has reduced BPs estimated subsea costs by 50% for Mad Dog II



Source: Deutsche Bank, Company presentation

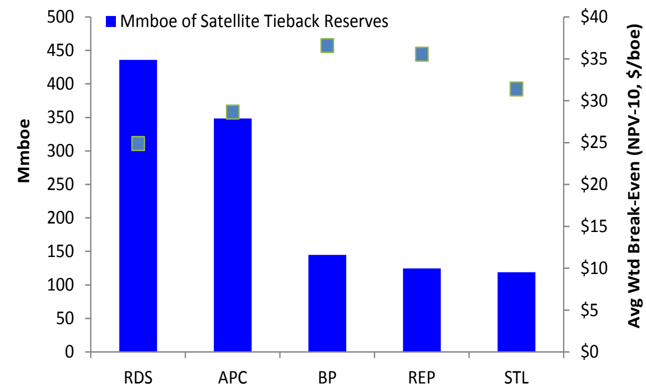
Further supporting improved capital efficiency is a concerted effort by producers to re-focus capital allocation towards higher efficiency development programs, such as tie-back opportunities and resource with greater proximity to existing infrastructure (see more on tie-back opportunities and economics on page 29).

Figure 32: Tiebacks provide attractive economics and increased shorter-cycle dev options (GoM DW below)



Source: Deutsche Bank, Wood Mackenzie

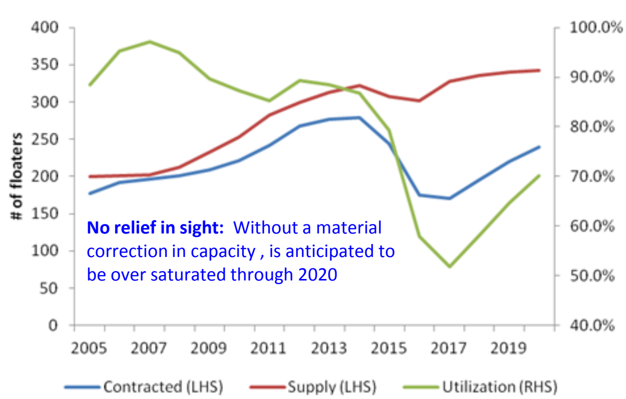
Figure 33: With APC and RDS holding a meaningful inventory of low-cost/short-cycle optionality in GoM

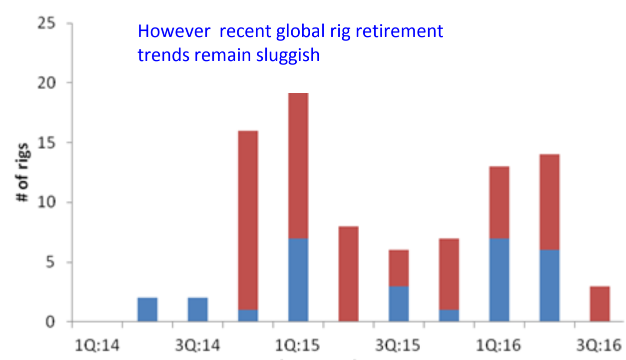


Source: Deutsche Bank, Wood Mackenzie

The net result of the various moving pieces is significant cost deflation in deepwater drilling and development. We estimate that well costs alone are likely down roughly 60% vs. pre-downturn levels (see Fig. 35). Assuming a rough breakdown of costs for your average deepwater development of: development drilling (60%), Facility/topsides (12%), subsea infrastructure (28%), we estimate that overall development costs are likely down 30-40% for an average deepwater development vs. 2014, with trends likely pointing to further deflation from here. In fact, unlike the US onshore, where we expect modest re-inflation in parts of the value chain beginning in 2017, we believe that cost deflation is likely to prove much more durable in the DW in the medium-term, given the slow return of capital and significant overcapacity across much of the sector.

Figure 34: Unlike the onshore, where cost inflation is likely to emerge across some key components in 2017, we expect a capacity-long floater market to provide leg-room for sustained cost deflation in the DW over the medium-term



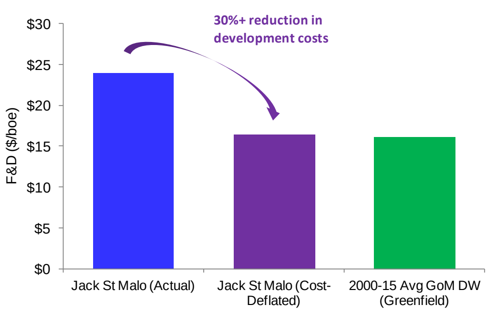


Source: Deutsche Bank

Figure 35: **The End-Game:** We see evolving deflationary offshore cost trends driving 30-40% reductions in headline development costs for ultra-deepwater projects (see "Re-visiting Project Costs for Jack/St Malo" below)

UDW GoM Cost Deflation Assumptions

	Metric	2013/ 2014	% Reduction	Target
Per Well Drilling				
Drill Days at 7500m	Days	155		108
Drill Days at 9500m	Days	196		137
Completion Time	Days	98		68
Total D&C Time	**Days**	**295**	**-30%**	**205**
Wells D&C per Year		1.2		1.8
Drilling Cost				
Average Day Rate	$1000/d	$600	-54%	$275
Average Spread Rate	$1000/d	$600	-37.5%	$375
Total Drilling Cost	**$1000/d**	**$1,200**	**-46%**	**$650**
Annual Drilling Cost	$MM	438		237
Average Well Cost	**$MM**	**$353**	**-62%**	**$133**
Steel (US MW HR Coil)	**$/tonne**	**$700**	**-29%**	**$500**



Re-Visiting Project Costs for Jack/St Malo (2010 FID, 2014 First Production)

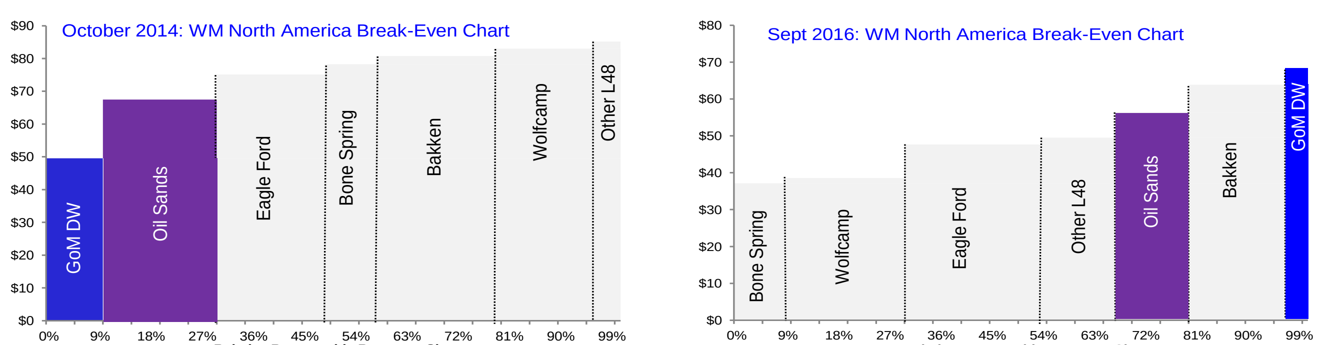
	Total Dev Cost Break-down	Substem Cost Break-Down	Actual	% Reduction	Target
D&C	60%				
Well Costs		90%	$240		$133
# of Wells			27		27
Installation, Other		10%	$720	0%	720
Total D&C			**$7,200**	**-40%**	**$4,321**
Hull	6%				
Materials, Fabrication		80%	$600	30%	$420
Installation, Other		20%	$150	0%	$150
Total Hull			$750	-24%	$570
Top-Sides	6%				
Materials, Fabrication		24%	$180	30%	$126
Equipment		32%	$240	10%	$216
Installation		27%	$203	10%	$182
Other		17%	$128	0%	$128
Total Top-Sides			$750	-13%	$652
Total Platform			**$1,500**	**-19%**	**$1,222**
Sub-Sea System Cost	21%				
Equipment		29%	$725	25%	$544
SURF		48%	$1,200	25%	$900
Installation		27%	$675	10%	$608
Total Sub-Sea			**$2,500**	**-18%**	**$2,051**
Pipelines	7%				
Support Vessels		51%	$408	35%	$265
Linepipe/Coating		18%	$144	20%	$115
S-lay with DP		18%	$144	10%	$130
Other		13%	$104	0%	$104
Total Pipeline			**$800**	**-23%**	**$614**
Total Costs ($MM)			$12,000	-32%	$8,208
Resource Size (Mmboe)			500		500
Implied F&D Cost ($/boe)	**$/boe**		**$24**	**-32%**	**$16**

Source: Deutsche Bank, IHS Wood Mackenzie

#2 – Deepwater economics can't compete with US onshore

For a large number of US investors, there is a persistent belief that deepwater economics just can't compete with the US onshore, with US shale effectively pushing deepwater developments (and for that matter, oil sands and other large, conventional projects) off of the cost curve.

Figure 36: The Evolution of US Onshore Break-Even Economics: Has the Deepwater Been Priced Out?



Source: Wood Mackenzie

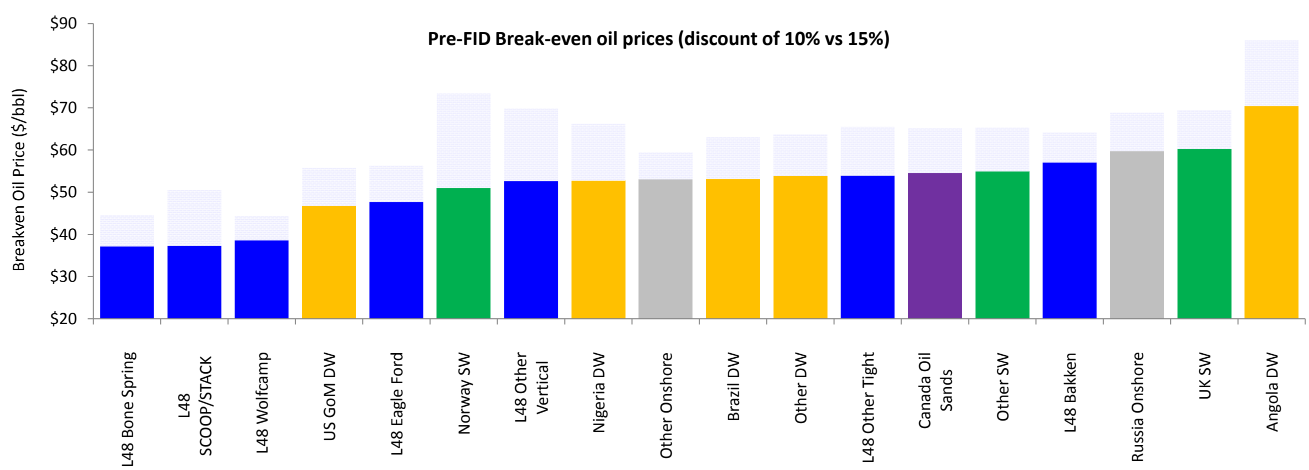
While US shale has certainly moved lower on the cost curve, and offers a unique combination of drilling visibility, capital flexibility, and quick capital payback/cash recycle (see section on deepwater "Challenges"; page 32), we believe that high quality resource will be both necessary and competitive, no matter the "bucket" (ie. US onshore, deepwater, oil sands, LNG, etc.).

In our view, the market has adjusted the cost structure of the US onshore in a relatively "real time" (and entirely appropriate) manner, but has done little to account for the changing cost structure in large, conventional assets (see cost curves below). When accounting for current trends in offshore/conventional cost structure, we estimate that high quality offshore projects are ultimately competitive, with top-tier projects breaking even in the low-$40/bbl range (see Fig. 45-47).

Further, given the ability of the industry to effectively lock in low cost structures in the offshore at project FID (the same phenomenon currently hurting operators that sanctioned projects in 2012-2014), and the likelihood of modest re-inflation in the US onshore beginning in 2017, we expect that relative risk actually favors longer-cycle, conventional projects at this point in the cycle.

Finally, while it may feel so in the current environment, we don't view the investment prospect as "either/or" for most diversified operators, as large IOCs will need to continue to invest across various business lines, both as a form of diversification, as well as the inability of large IOCs to deploy $20 Bn+ a year into any single area.

Figure 37: While the deepwater is not without challenges vs. the US onshore, DW project economics stack-up well vs. other conventional and unconventional (oil sands) supply sources



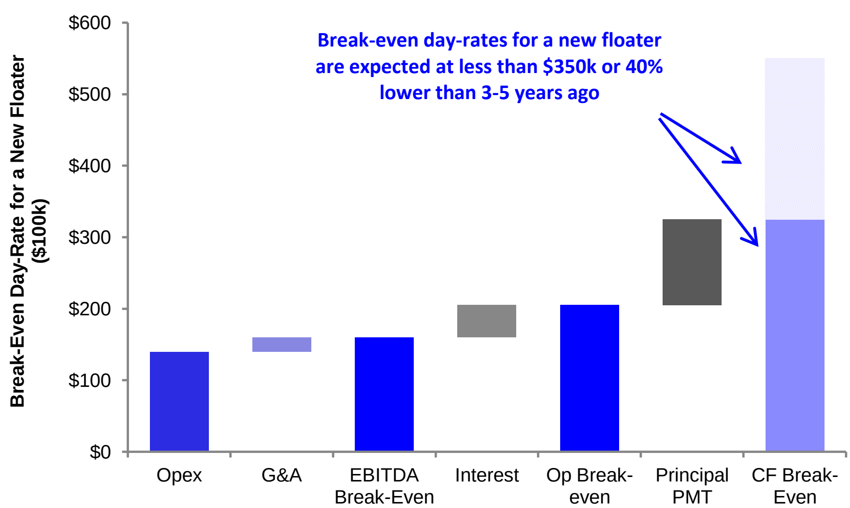
Source: Deutsche Bank, Wood Mackenzie

#3 – Offshore Drillers Cannot Support Needed Upstream Cost Deflation

In trying to frame a lower-bound on potential offshore cost deflation, investors are often quick to argue that the cost deflation needed to drive enhanced deepwater project economics is constrained by the ability of the supply-chain to absorb those same cost reductions. We would argue that the similar low commodity price induced efficiency gains seen with upstream operators are also being observed to an extent with regard to the offshore drillers.

Offshore drillers have seen their operating rig costs decrease between 25%-35% since 2014 and while decreased activity (warm/cold stacked operating costs are ~$40k/$15k per day for drill-ships) has certainly helped; an increased focus on operational execution and cost optimization across the much broader industry supply-chain provides evidence of a sector that is in-fact optimizing its cost structure. Ensco has noted 25% rate reductions in offshore labor, repair and maintenance costs, and in insurance premiums/vendor pricing since 2014 while Seadrill has disclosed that break-even day rates for new-build floaters are down ~40% vs. 3-5 years ago

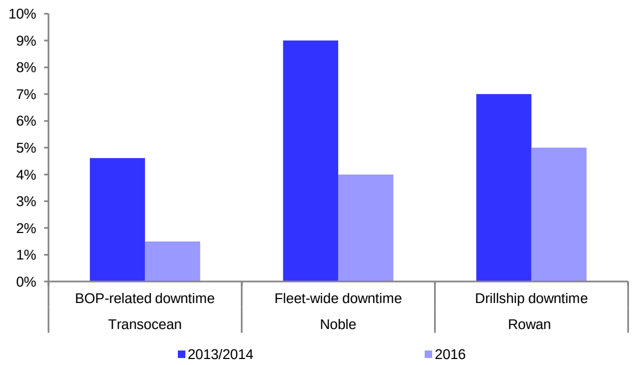
Figure 38: Improving Efficiencies Across the Supply Chain



Source: Deutsche Bank, SDRL

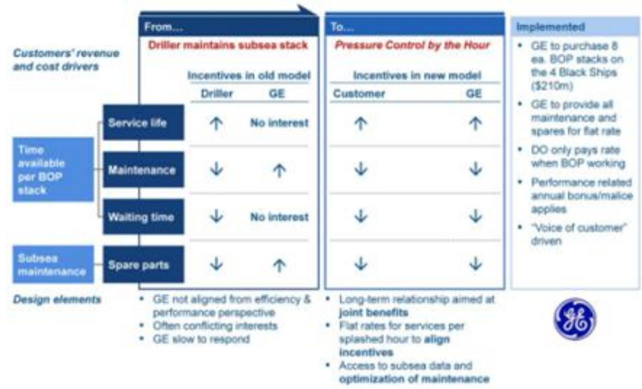
Toward increasing operator efficiency, earlier this year, Diamond Offshore announced a new BOP efficiency model in a partnership with GE that would aim to increase subsea stack availability (>50% of a rig's downtime is related to the stack according to partnership) by placing accountability for equipment failures with OEM directly. Other operators have already seen significant reductions in downtime with Noble and Transocean speaking to ~55-65% reductions in down-time in 2016 vs. 2013/2014 levels (with Rowan noting a 30% reduction from 2015).

Figure 39: Reducing Rig Downtime



Source: Deutsche Bank, Company Presentation

Figure 40: Diamond Offshore/GE's "Pressure by the Hour" Efficiency Model Aims to Reduce BOP Downtime



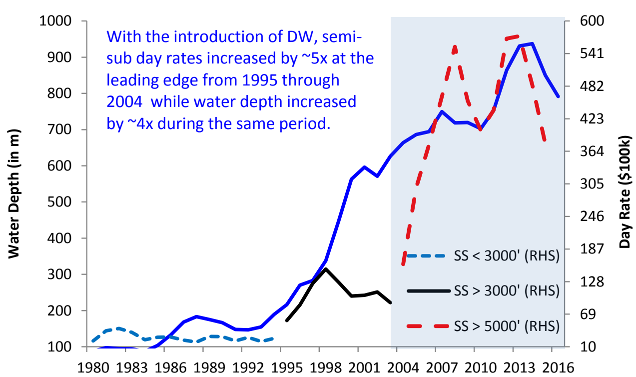
Source: Deutsche Bank, Company Presentation

#4 – The "easy oil" is gone; Technical challenges are driving structural cost inflation

A common refrain from investors regarding the evolution of deepwater cost structures is that "all of the easy oil is gone", and structurally higher costs are here to stay due to challenging geology, technical challenges, etc. The obvious problem with this statement is that technical challenges relative to the ease of extraction have been increasing for 150 years – however, technological improvements have allowed costs to remain reasonable.

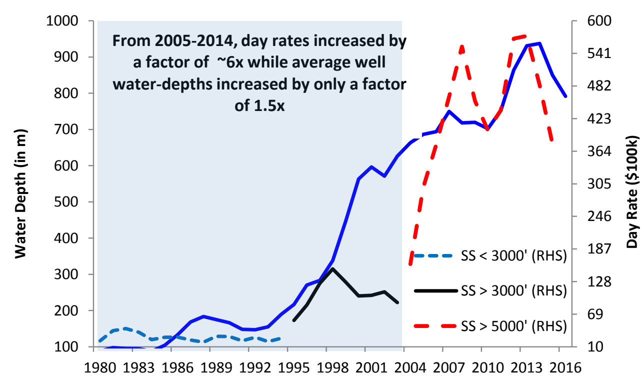
- **Supply/Demand vs. Technical Creep: Nothing we haven't seen before**. It is often referenced that the sheer depth and pressure of current developments, or the presence of salt canopies, is driving irreversible cost inflation. And while in some regards this is true (ie. 30,000ft of pipe will cost more than 20,000ft), depth and pressure have been increasing for decades (with little structural correlation in cost), and today's "cutting edge" technology (ie. 20k psi kit), will soon become tomorrow's standard. If anything, the deepwater rig market has reminded us that supply-demand matters much more than geology/technology (water depths haven't reversed, just costs).

Figure 41: While costs have often scaled with complexity in the past…



Source: Deutsche Bank, Wood Mackenzie

Figure 42: …the increase in offshore costs post 2004 far outpaced increases in technological complexity

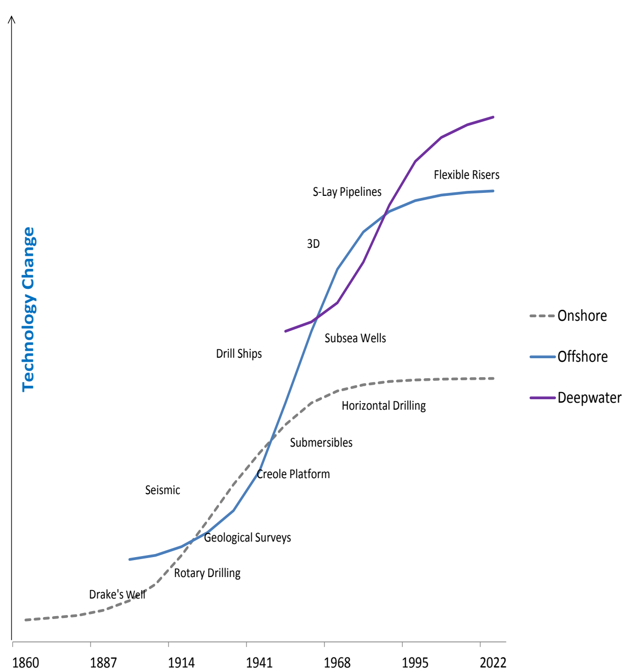


Source: Deutsche Bank, Wood Mackenzie

- **Development concepts/strategies are evolving**. Over the past few years, we have seen a gradual shift in strategy to include smaller, phased developments, increased standardization across facilities (PBR's phased pre-salt development, APC's 'design one, build two" approach, etc) and well design (rather than historical trend towards customization), and creative, mutually beneficial partnerships (ie. COP/CVX/BP partnership in GoM). We expect commodity and cost pressures to continue driving cost-rationalizing efforts at the margin.
- **Technological advances**. While there is no "Moore's Law" equivalent with regard to offshore oil and gas developments, the industry has proved itself responsive toward implementing cost-optimizing technological solutions to increasingly complex offshore developments. From 3-D (and 4-D) seismic to multi-phase pumping to dual-gradient drilling and multi-zone completions, recent advances in technology have facilitated the economic development of HP/HT, low energy

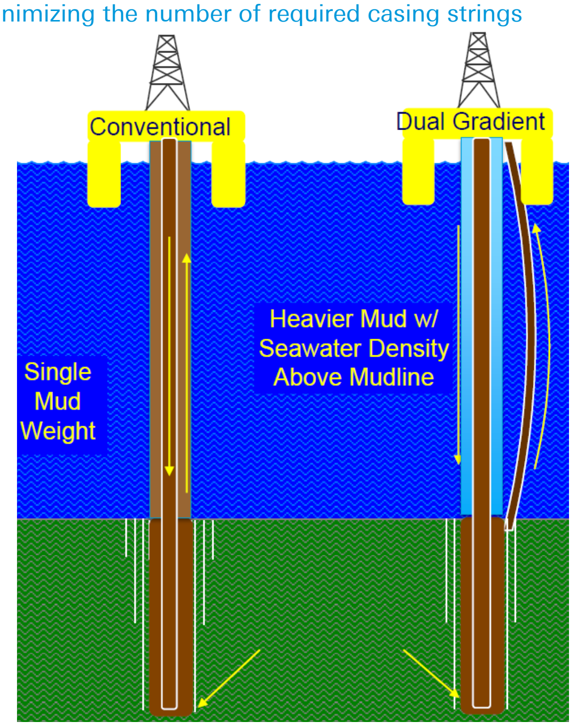
fields like in the GoM Lower Tertiary. For example, dual gradient drilling (which provides a more dynamic pressure monitoring system) can reduce the number of casing strings needed to maintain system integrity amidst increasing bottom-hole pressure - decreasing both material costs and drilling time to TD. Enhanced completion designs like multi-zone frac pack stimulations have significantly reduced completion days and drilling full-cycle D&C times to 200-225 days at CVX's Jack/St Malo development. Recent subsea technological advances have allowed operators to increase recovery rates from low-energy fields (Shell is test-running a new generation of sea floor pumping technology as part of its Stones project – 2016 start up).

Figure 43: **The O&G Technology Time-Line**: Always Moving Up



Source: Deepwater Petroleum E&P: A non-technical guide

Figure 44: **Dual Gradiant Technology, An Example**: Has improved drilling efficiency (and reduced costs) by minimizing the number of required casing strings

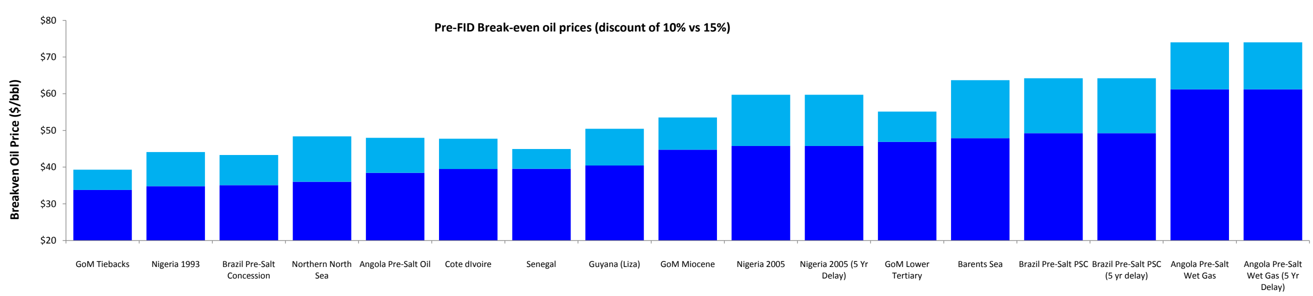


Source: Deutsche Bank, CVX Presentation

However, All Barrels are Not Created Equal

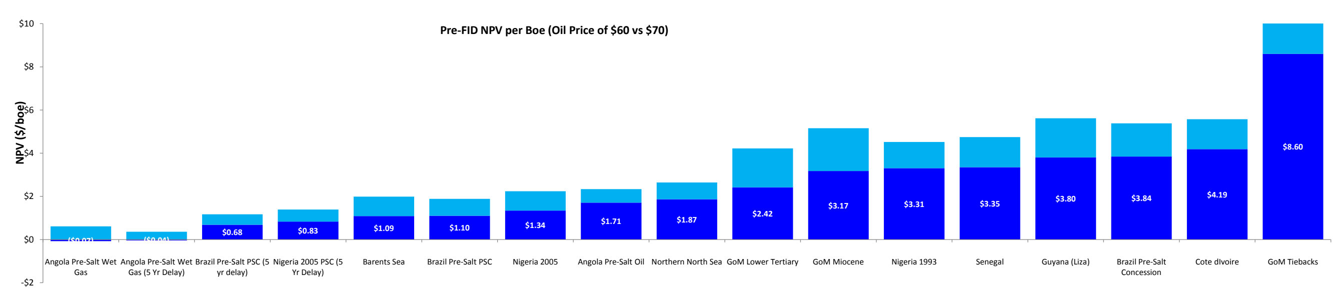
While deepwater developments are often lumped into a single category by investors, the reality is that conditions and economics vary widely across potential developments, no different than the full spectrum of US onshore assets (Mississippian or TMS, anyone?). In short, not all barrels are created equal. While opacity and/or lack of data can make the offshore difficult to analyze, we look at a number of factors below that have the potential to make or break a potential project, including: fiscal terms, resource density, field size, and proximity to existing infrastructure.

Figure 45: Deep-Water Cost Curve (Break-Even Oil Price)



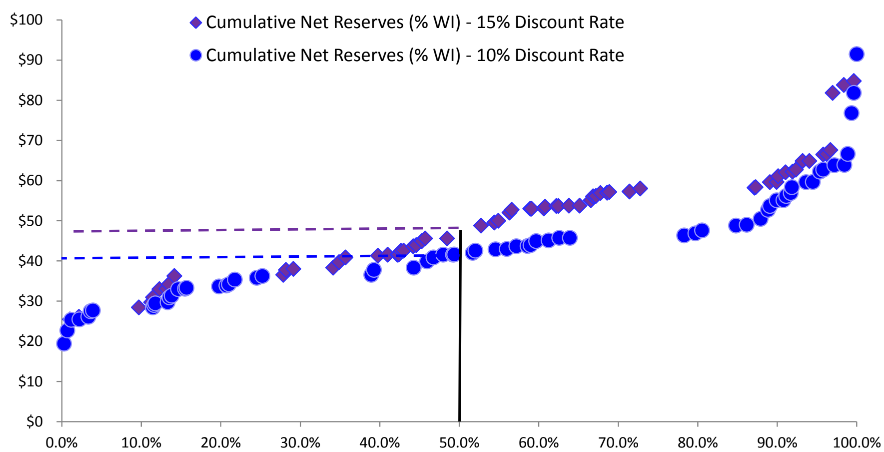
Source: Deutsche Bank, Wood Mackenzie

Figure 46: Deep-Water Cost Curve (NPV-10)



Source: Deutsche Bank, Wood Mackenzie

Figure 47: **DB Aggregate New Project Break-Even Oil Prices:** In a normalized cost environment, we estimate ~50% of new deepwater reserves break-even at $45/$52 at a 10%/15% discount rate

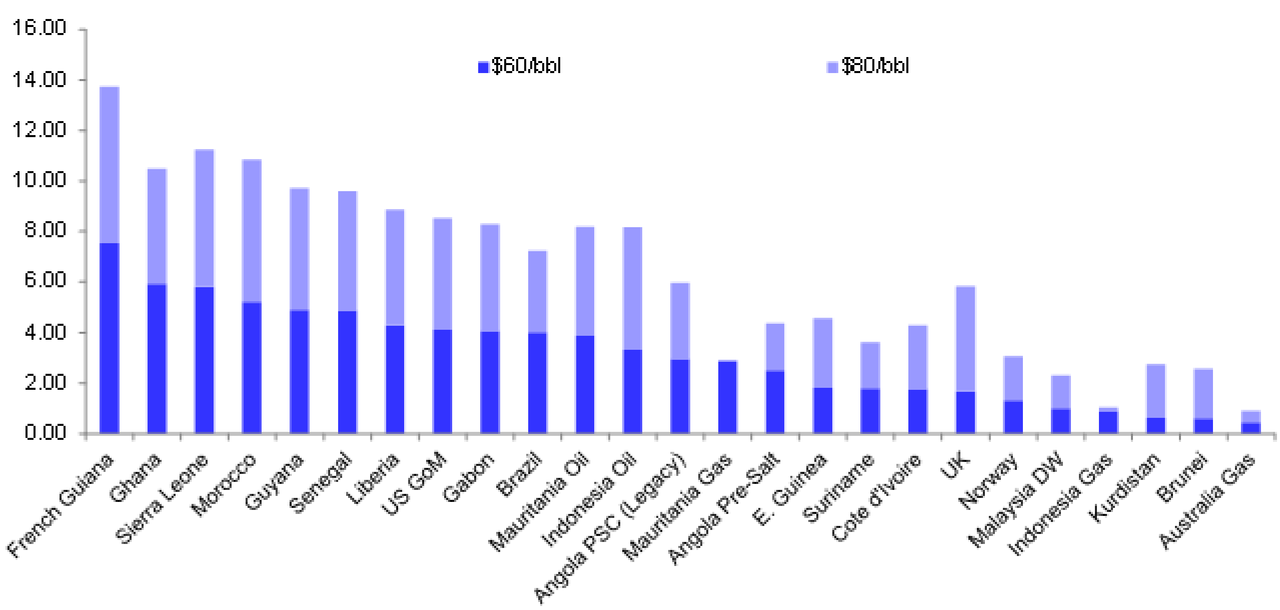


Source: Deutsche Bank, Wood Mackenzie

Fiscal Terms

On the surface, one of the most visible differentiators of resource value is the fiscal terms set by local governments, which can vary significantly, often reflecting basin maturity and/or geopolitical stability. As seen in Figure 48 below, the impact on resource value can be dramatic, with the PV of a discovered, but yet-to-be-developed barrel of resource at $60/bbl crude ranging from ~$7.50/boe at the high end to under $1.00/boe in the most punitive regimes.

Figure 48: NPV per barrel by global regime ($/boe)

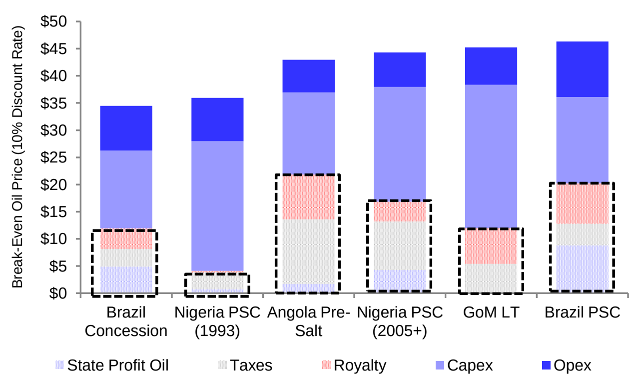


*Source: Deutsche Bank, *Assumes $70/bbl long-term oil price*

While significant resource and high success rates in the US Gulf of Mexico have long drawn high levels of interest, it is the combination of this AND one of the most attractive global fiscal regimes, that has continued to keep the basin at the forefront of exploration and development portfolios – even more so at low to moderate crude prices. In contrast, Angola, which has been one of the largest drivers of discovered resource over the past 20 years, has seen a significant drop in investment and remains marginal in most company's portfolios in the current environment given challenging existing fiscal terms. As shown in Figure 50, Angola's effective tax rate or the government's share (royalty, tax, and share of profit oil) is close to 60% or nearly double that of the US GoM which has among the lowest effective tax rates for deepwater developments.

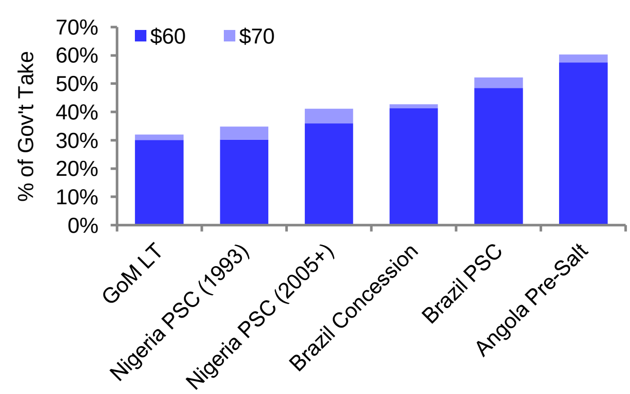
Even within the same country, fiscal terms can vary significantly depending on the license/block in question. For example, while we see an average break-even of $35/bbl for a pre-salt Brazil concession development, we model a break-even closer to $45/bbl for the same asset under a PSC regime.

Figure 49: Fiscal terms vary significantly and are often as critical a driver of project economics as costs in PSCs



Source: Deutsche Bank, Wood Mackenzie

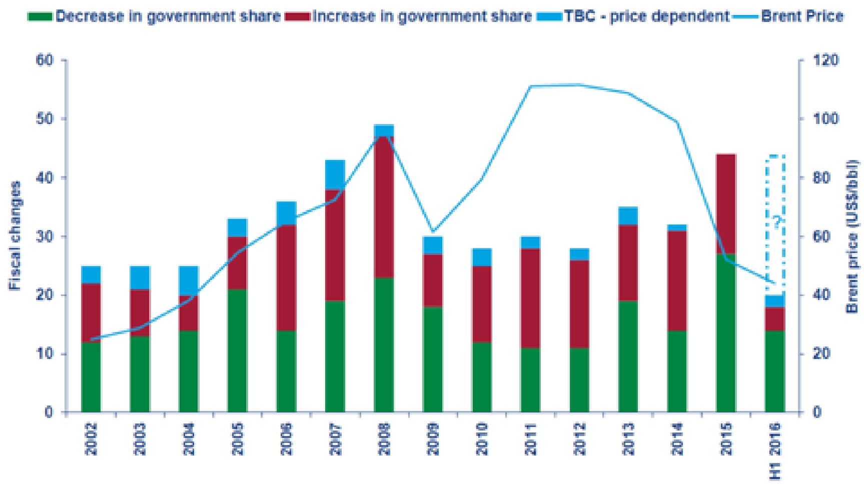
Figure 50: Effective tax rate sensitivity to crude



Source: Deutsche Bank, Wood Mackenzie

Of course, fiscal terms can change – in both directions - and 2015 saw the most adjustments to fiscal regimes since the mid-2000s, predominantly a decrease in government share. The first half of 2016 has continued at a relatively elevated pace, with additional changes likely during 2H16. **With large IOCs likely to be operating under a relatively constrained capital budget in the medium-term, and, at least in the near-term, largely long resource opportunities and short capital, we expect that governments may increasingly look to relax fiscal terms as a way of trying to attract scarce investment**. This is particularly relevant in regions with attractive resource quality and a punitive government take (see recent changes in Mexico, and increasing pressure in countries such as Angola and Brazil).

Figure 51: 2015 saw the highest level of fiscal change since the mid-2000s



Source: Wood Mackenzie

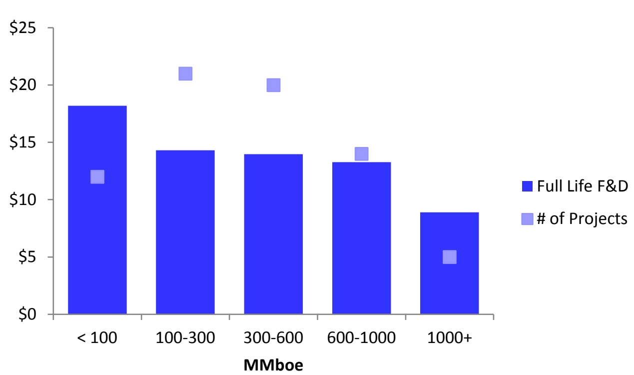
Resource Size

Resource Size Matters

Outside of fiscal terms, resource size remains one of the primary drivers of field economics, and where, all things considered, bigger is almost always better. Broadly, this is primarily because a relatively high level of fixed costs (facility, certain amount of subsea infrastructure, etc.) can be spread across a larger resource base, generating significant economies of scale.

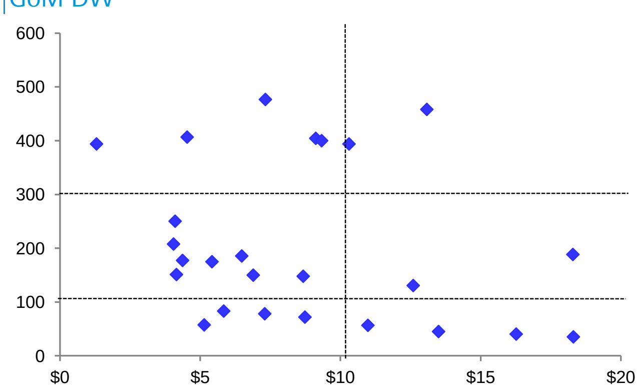
A sampling of over 70 global deepwater projects that are either currently producing or under development show F&D costs on average falling as resource size increases, ranging from $18/boe for projects under 100 mmboe, to ~$9.00/boe for projects over 1,000 mmboe. The size of the resource, and the subsequent reduction in unit costs, can have a dramatic impact on project economics. In the US Gulf of Mexico, we estimate that a range of field size from 100- 600 mmbbl could result in a NPV/boe of $1.65- $5.00/boe, and an IRR of 14%- 28% at $60/bbl (see figure and assumptions below).

Figure 52: Avg F&D ($/boe) per Resource Size



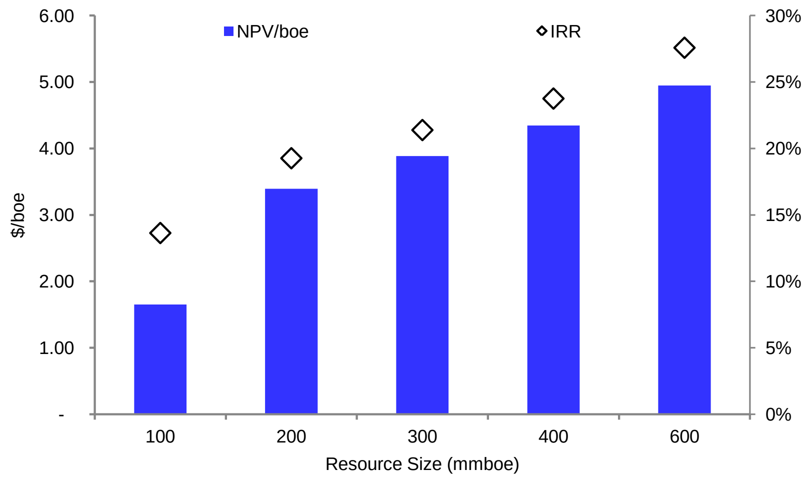
Source: Deutsche Bank, Wood Mackenzie, 3yr rolling avg, based on wells spud in year, includes GoM DW, Brazil, and West Africa (Angola, Nigeria, Congo, Ghana, excludes tiebacks

Figure 53: Initial F&D ($/boe) by Resource Size in the GoM DW



Source: Deutsche Bank, Wood Mackenzie, Resource Size (Mmboe) vs. Initial F&D ($/boe) - Y vx. X axis, excludes tiebacks

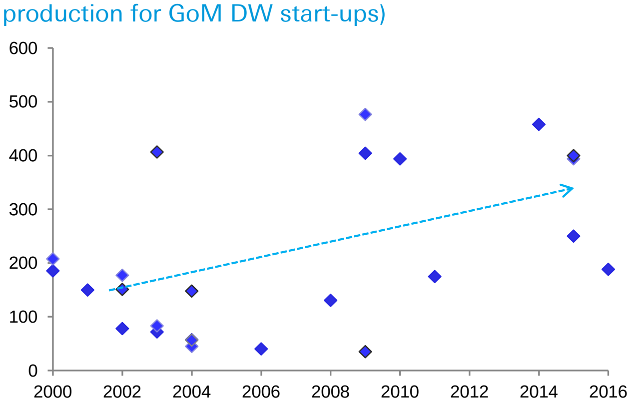
Figure 54: Economics improve significantly with increased resource size



Source: Deutsche Bank

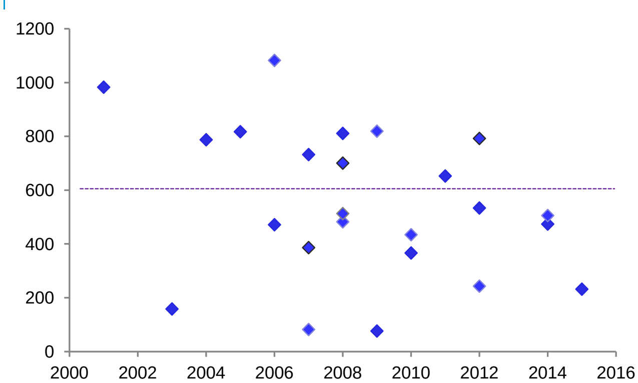
While average resource size of discoveries declined for years in the US Gulf of Mexico, the size of fields reaching first oil has been gradually increasing since ~2006, a reflection of 1) a number of large discoveries since 2000 as improvements in seismic imaging has improved targeting of previously challenged resource, and 2) economic thresholds favoring larger resource development. These trends, as well as a significant number of large discoveries in the Lower Tertiary should keep the US GoM amongst the most active deepwater regions going forward. In contrast, the trend over the past 10 years in West Africa has been towards smaller developments, as the world-scale developments of the early to mid-2000s in Angola and Nigeria have given way to smaller, satellite developments.

Figure 55: DW GoM production has increasingly been driven by larger-sized resources (MMboe by year of first production for GoM DW start-ups)



Source: Deutsche Bank, Wood Mackenzie, excludes tieback, not shown are Mad Dog (I, II, first production in 2005), Atlantis (first production in 2007) and Thunderhorse (first production 2008) all of which have an estimated discovered resource size of 800 MMboe

Figure 56: While West Africa has been mostly flat (Resource Size in MMboe by year of first production)

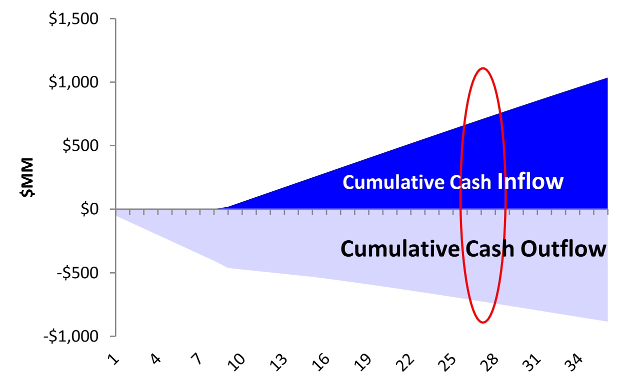


Source: Deutsche Bank, Wood Mackenzie, Resource Size (Mmboe) vs. Initial F&D ($/boe) - Y vx. X axis, excludes tiebacks

Proximity to infrastructure

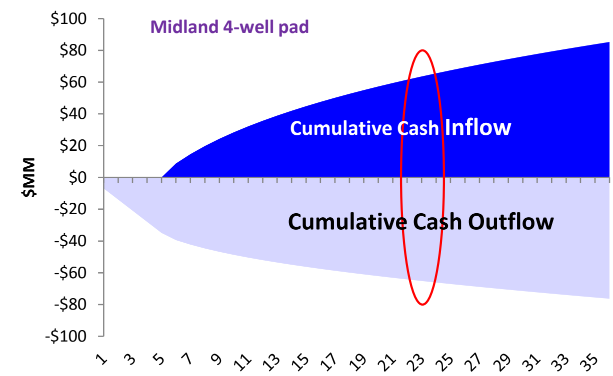
Proximity to existing infrastructure is a potential offsetting factor in the push towards larger resource size. As a number of the large IOCs have openly discussed a shift towards short/mid-cycle capital spend in the medium-term, we expect that **tieback developments** will play an increasingly important role, particularly in the GoM DW and the North Sea, where infrastructure is plentiful. While the absolute PV of tieback opportunities is clearly smaller than those presented by large, stand alone developments, the shorter payback period and shape of the cash flow profile have significantly improved their relative attractiveness. We estimate a payback period of ~28 months for a 2-well satellite development in the Middle Miocene – mostly in line with a modeled 4-well pad in the Permian's Midland Basin (24 months).

Figure 57: Subsea tiebacks offer a competitive capital allocation alternative to the Lower 48 onshore - We est a payback period of ~29 mo for a 2-well GoM Tieback



Source: Deutsche Bank, X-axis shows months from initial investment

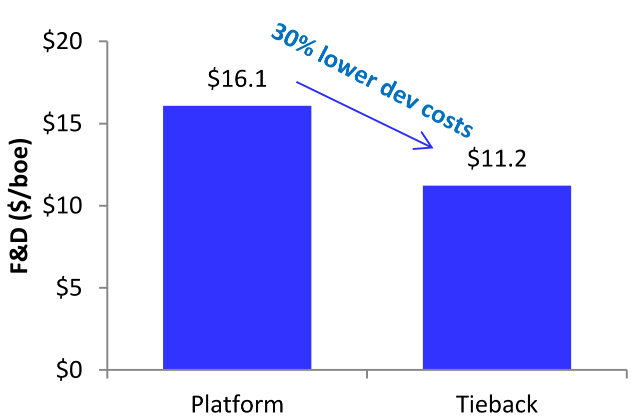
Figure 58: And a comparable pay period of 24 mo for a 4-Well Midland Pad –



Source: Deutsche Bank, X-axis shows months from initial investment

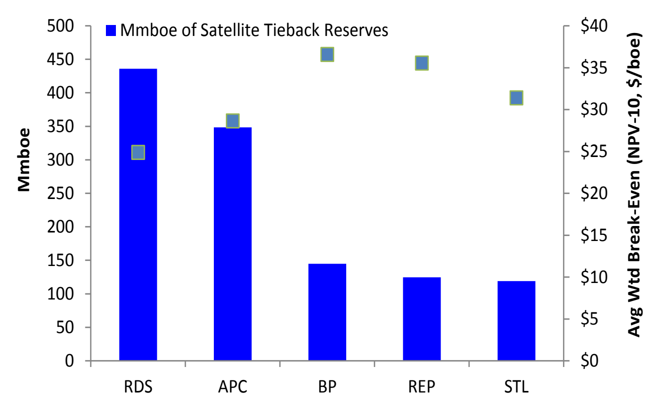
Across our coverage group, we see the greatest upside from satellite tieback options at **RDS** and **APC,** who has nearly 350 MMboe of highly attractive net reserves in the GoM – roughly the size of a large Miocene reservoir!.

Figure 59: Tiebacks provide attractive economics and increased shorter-cycle dev options (GoM DW below)



Source: Deutsche Bank, Wood Mackenzie

Figure 60: With APC and RDS holding a meaningful inventory of low-cost/short-cycle optionality in GoM



Source: Deutsche Bank, Wood Mackenzie

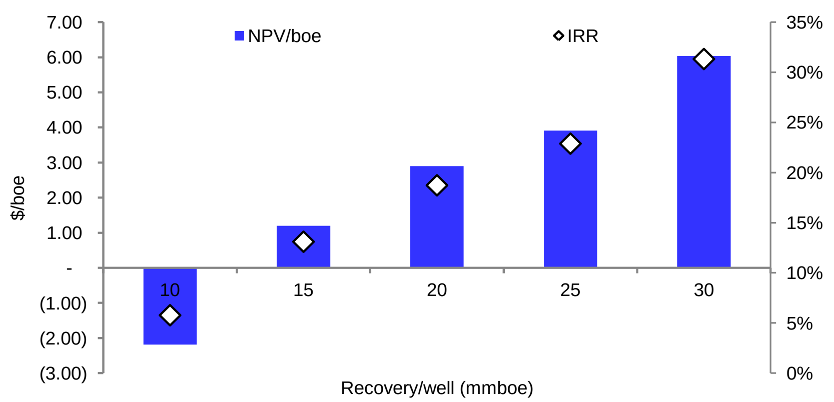
Resource Density/Well deliverability

Often underappreciated by investors, particularly given lower visibility than absolute resource size, is the impact of resource density, referring to: 1) recovery per well (well deliverability), and 2) resource concentration/proximity (proximity to planned infrastructure). Each has a significant impact on required drilling and/or infrastructure spend, and ultimately, a dramatic impact on project returns; often a larger factor than absolute resource size in determining project viability.

Recovery per well (Well deliverability)

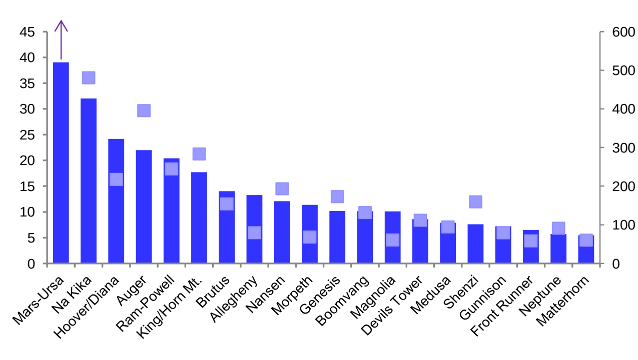
In simple terms, well deliverability determines ultimate recovery per well, which drives how many wells are necessary to develop a given resource. With development drilling/completion costs often representing 40%-60% of total project capex, this is a significant factor in driving project economics. Well deliverability is ultimately driven by a wide variety of factors, although reservoir quality (porosity, permeability), oil quality (API gravity), reservoir pressure and Gas to Oil Ratio (GOR) are amongst contributing factors.

Figure 61: Economics improve significantly with well deliverability



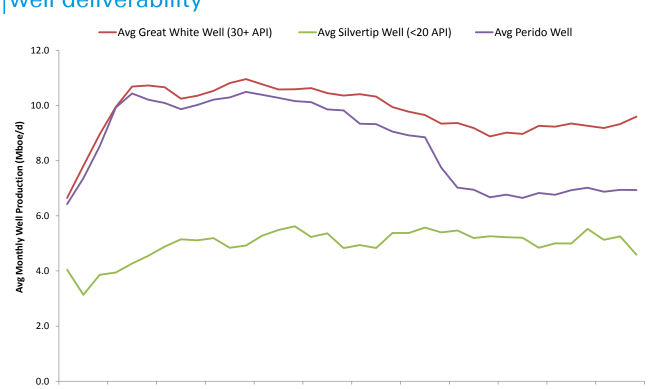
Source: Deutsche Bank; *Based on a potential US Gulf of Mexico development

Figure 62: Large, continuous reservoirs…



Source: Deutsche Bank

Figure 63: …and API gravity are two factors impacting well deliverability



Source: Deutsche Bank

Reservoir/Resource proximity

Resource density in determining (ie. minimizing) required non-drilling infrastructure spend is another meaningful driver of project economics. For example, it is far less costly to develop a single, 500 mmboe structure, than it is to develop five separate, 100 mmboe structures requiring either multiple hub facilities or significant subsea tie-back infrastructure.

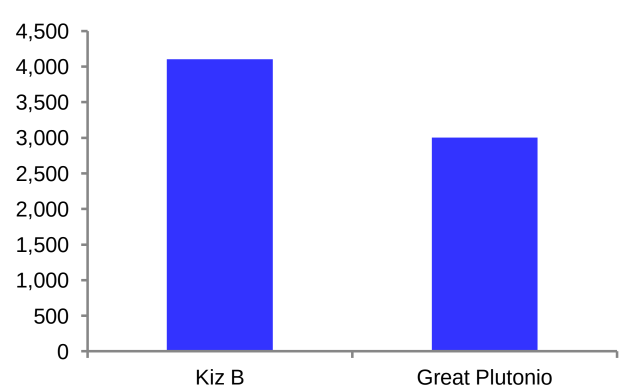
A prime example of this was the contrast between of two of the larger developments in the Congo Basin offshore Angola during the mid-2000s: Kizomba B (Block 15) and Greater Plutonio (Block 18). As summarized in Figure 64, despite both a similar cost environment and similar total resource size, Greater Plutonio's more scattered resource (5 primary reservoirs vs. 2 at Kizomba B) resulted in nearly three times the level of required subsea capex (~$3 billion vs. $1 billion; 26% vs. 13% of total capex), driving total F&D/boe of ~$15.58/boe vs. $9.77/boe at Kizomba B, and reducing the NPV of future cash flows (if developed today) by ~$1.0 Billion (25% reduction), and reducing project IRR from 30% to 20%.

Figure 64: Resource Density: Kizomba B (B15) vs. Greater Plutonio (B18)

	Kizomba B (Block 15)	Greater Plutonio (Block 18)
Resource Size (mmboe)	817	732
# of Reservoirs	2	5
# of Producers	45	25
# of Water Injectors	31	20
# of Gas Injectors		6
Recovery per producer (mmboe)	18	29
Recovery per well (mmboe)	11	14
Development Overview		
Water Depth (m)	1,100	1,300
Length of subsea flowlines (km)		150 km of flowlines; 110 km of instrument and control umbilicals
Total subsea capex)$MM)	1,000	2,973
Total capex ($MM)	7,984	11,401
Subsea % of Total Capex	13%	26%
Subsea Capex per Barrel ($/boe)	1.22	4.06
Total F&D ($/boe)	9.77	15.58

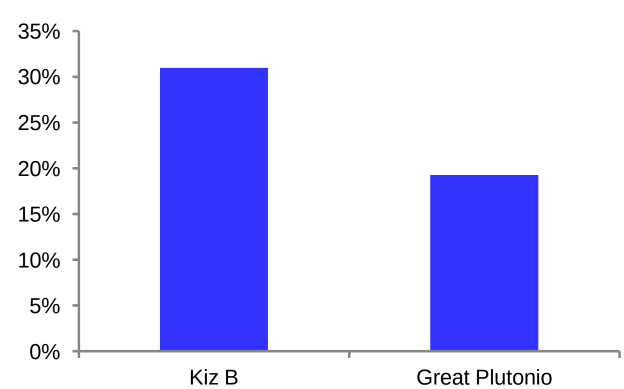
Source: Deutsche Bank, Wood Mackenzie, Company data

Figure 65: Over $1.0 Billion of additional NPV…



*Source: Deutsche Bank; *Economics assume actual development strategy and current commodity environment*

Figure 66: …and significantly higher rate of return



*Source: Deutsche Bank; *Economics assume actual development strategy and current commodity environment*

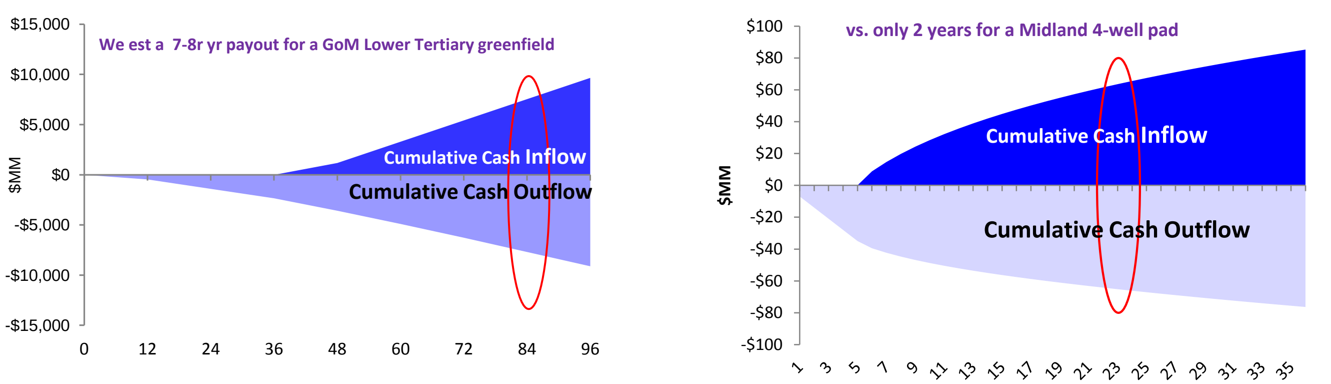
Risks and Challenges

Though more competitive than the market believes, meaningful challenges will continue to drive an increasing share of discretionary capital to US shale, including: geologic risk, project execution risk, geopolitical risk, and capital inflexibility. Adjustments to development strategies and scope can mitigate some risk, and large, diverse IOC budgets will invest across the spectrum, but failure to evolve would demand a higher rate of return, with an increase to 15% required IRR (vs. 10%) increasing average breakevens by $7.50/bbl.

Longer Full-Cycle Cash Cycles

While tie-back cash cycle times are more comparable to those found in the US onshore (2-2.5 yrs), meaningful growth in deepwater production will follow increased development/sanctioning of large green-field projects for which the cash pay-back cycle may be closer to 7-8 years from the time of initial development investment.

Figure 67: The cash-cycle/payback period for green-field DW projects is ~3-4x longer than for shale

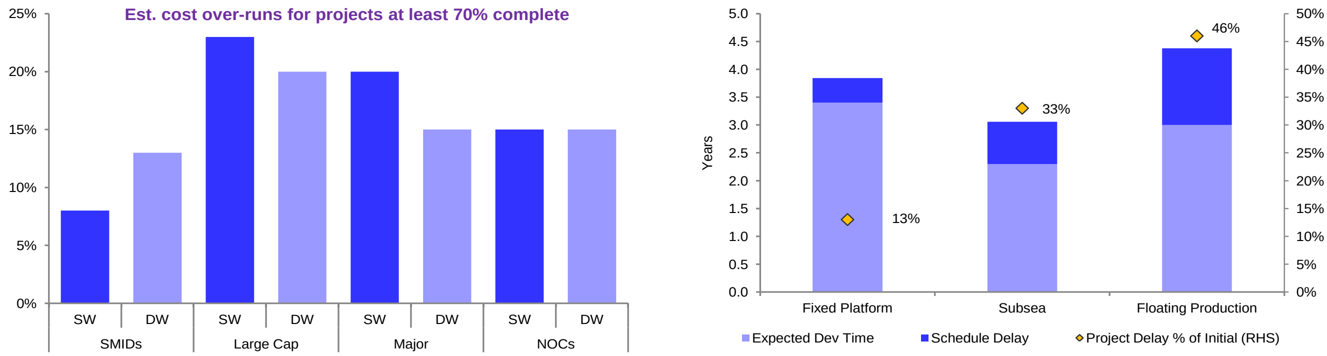


Source: Deutsche Bank, x-axis represents months from first spend

Risk adjusted rate of return

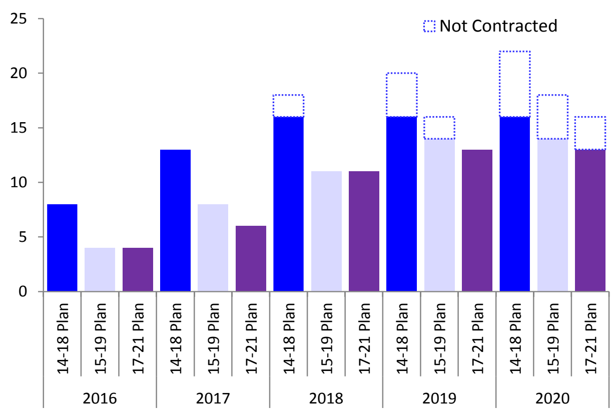
Pre-FID Execution Risk: Based on Wood Mackenzie data of projects that are at least 70% complete, cost over-runs for deepwater projects have ranged on average from 13% to 20% with scheduling delays on average of 33%/46% with respect to initial time-lines for subsea/floating platform developments respectively. While technological complexity often increases the likelihood for cost over-runs and project delays, we find a stronger relationship with geography. Increasingly higher local content requirements have resulted in increased lead-times in West Africa (from 6-8 years between 2000-2005 to almost 10 years after 2008); while delays to the development of Brazil's pre-salt resource have been chiefly driven by corporate-related headwinds at national oil company Petrobras. In the US, despite the challenges associated with increasing average water depth/measured depth we find that from 2000-2015 the average time from sanction to first production has remained around 3 years.

Figure 68: Deepwater project delays and cost over-runs



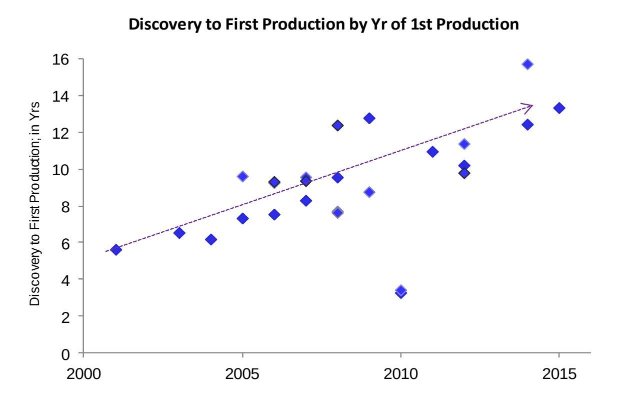
Source: Deutsche Bank, Wood Mackenzie

Figure 69: PBR's Platform Count in Brazil's Pre-Salt



Source: Deutsche Bank, Company presentations, By cumulative platform count

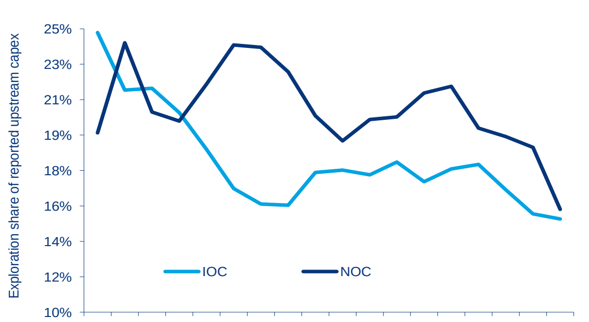
Figure 70: An increase in West Africa lead-times



Source: Deutsche Bank, Wood Mackenzie, Discovery to First Production

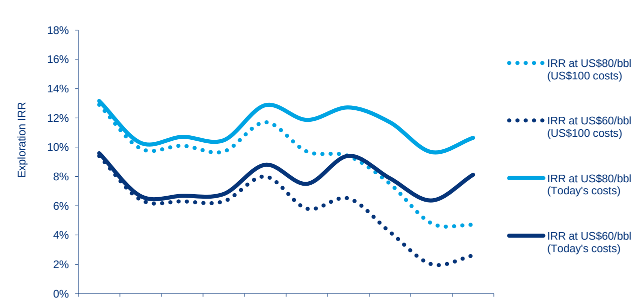
E&A Impact on Full-Cycle Returns: While much of this note has focused on project economics for pre-FID projects, the full-cycle cost of a deepwater development includes E&A. According to Wood Mackenzie, average IRRs for E&A (see Fig 72), have been at or below 10% since 2010 and have remained below 15% since 2006 – highlighting both the low success rates associated with exploration and high drilling and seismic costs.

Figure 71: E&A as a % of Upstream Capital



Source: Deutsche Bank, Wood Mackenzie

Figure 72: E&A Value Destruction



Source: Deutsche Bank, Wood Mackenzie

Corporate Snapshots

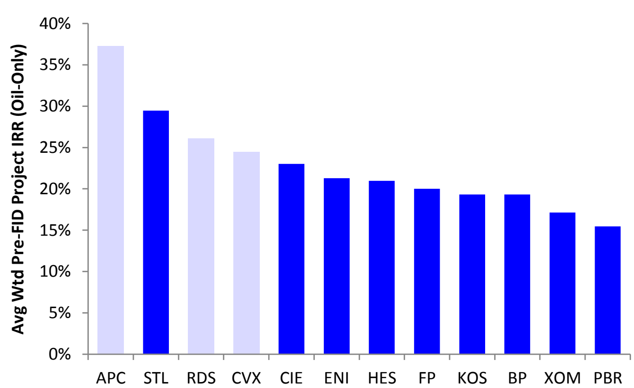
The Upstream Standouts

As large numbers of operators have exited the deepwater in recent years (COP, MRO, DVN, etc.), the number of players involved has consolidated considerably. Based on the depth and quality (i.e., weighted average IRR of opportunity set) of deepwater portfolios and importance to 2016-2025 growth strategies (or monetization strategies, for some), we view **APC, CVX, RDS, KOS** and PBR as best positioned to benefit from a better than expected outlook in the deepwater. We upgrade APC from Hold to Buy (See today's note "Diversified Drivers of Differentiated Growth", 13 October 2016), where a unique strategy continues to add value, and high-return tieback inventory trails only RDS. CVX, RDS have strong pre-FID portfolio optionality, advantaged positions in leading basins, US GoM and Brazil, and amongst the highest exposure to drilling cost deflation via coming expiry of current contracts.

KOS offers a relatively low-risk floor (stable production/cash flow and cash neutrality at $50/bbl crude) with meaningful potential catalysts via asset farm-down in Mauritania/Sengal (4Q16) and high impact exploration program in 2017-18.

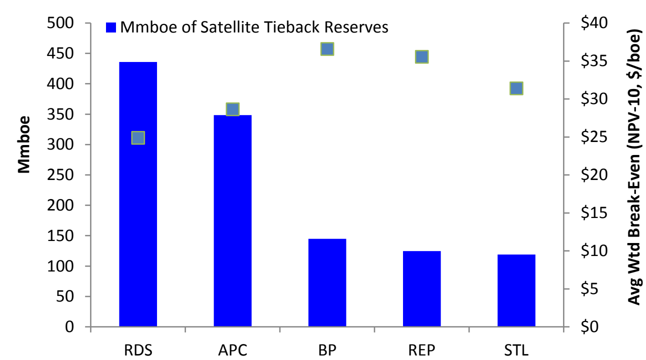
Highest leverage in our coverage is clearly at CIE, a "special situation" where we see attractive risk/reward and multiple potential catalysts in the next 6 months (Angola asset sale, debt restructuring/capital raise), although offering a risk profile that may not be attractive for many investors.

Figure 73: Under-pinned by a material tieback inventory (APC, RDS) and high-quality green-field pre-FID optionality we see APC, RDS, and CVX as relative standouts



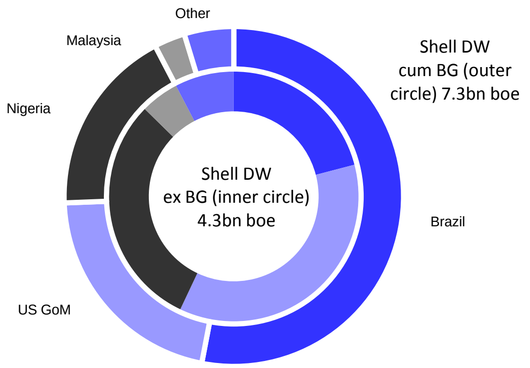
Source: Deutsche Bank, Wood Mackenzie

Figure 74: Trailing only RDS, APC boasts the largest /most attractive satellite tieback inventory in the GOM



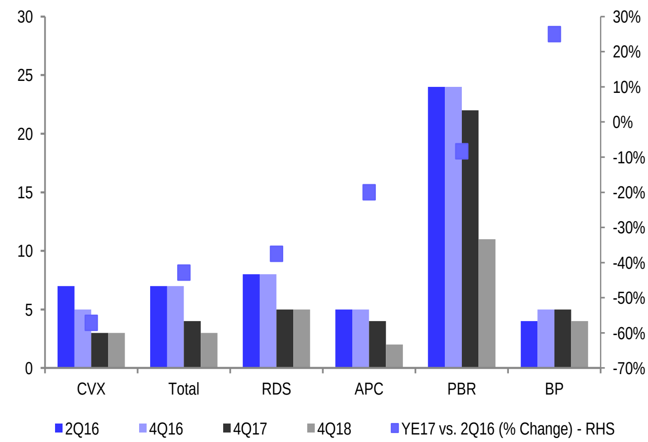
Source: Deutsche Bank, excludes under-dev and recent start-ups, reserves are net and ex in-fill drilling

Figure 75: The deepwater opportunity: Post BG c7bn boe with a weighting to high margin Brazil and US GoM



Source: Deutsche Bank, excludes underdevelopment and recent start-ups, reserves are computed on a net basis and exclude in-fill drilling opportunities

Figure 76: With 60% fewer UDW rig commits by YE17 (and LT GoM exposure), CVX is relatively well-positioned to capitalize on deflationary cost trends vs. peers



Source: Deutsche Bank, Wood Mackenzie

Offshore Drillers

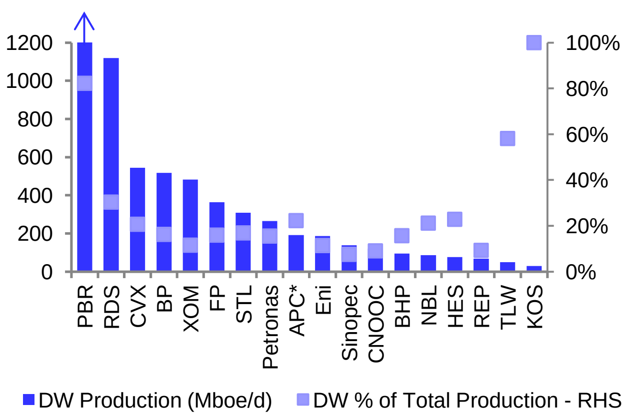
While offshore drillers will be challenged as the industry wrestles with a supply over capacity over the medium-term, the following buy-rated names in our coverage offer exposure into a longer-term recovery in the deepwater while offering less direct exposure to the over-supplied floater market:

- Oceaneering (OII- BUY, USD28.36)- Pure play on the number of DW projects/DW demand. While we have a negative view on the drillers due to over-supply, we have a positive view on DW activity/demand long-term.
- Schlumberger (SLB- BUY, USD 82.33)- Big service co most exposed to exploration, deepwater and international. All of those segments will benefit from growing DW activity.

Wood Mackenzie Deepwater Corporate Benchmarking

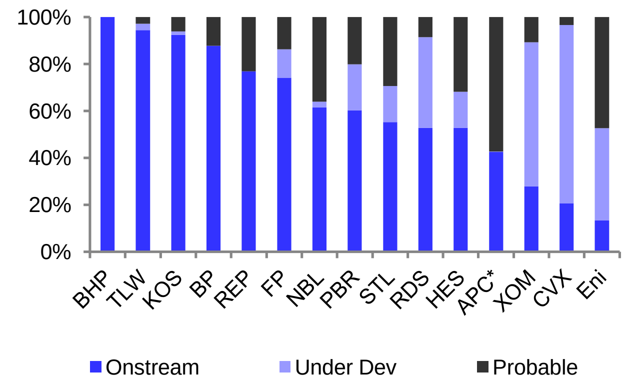
Corporate Trends in Production and Reserves

Figure 77: 2016 Deepwater Production



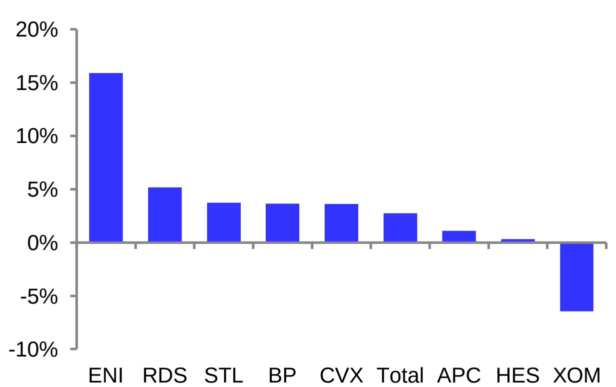
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 78: 2016-2025 DW Production by Dev Type



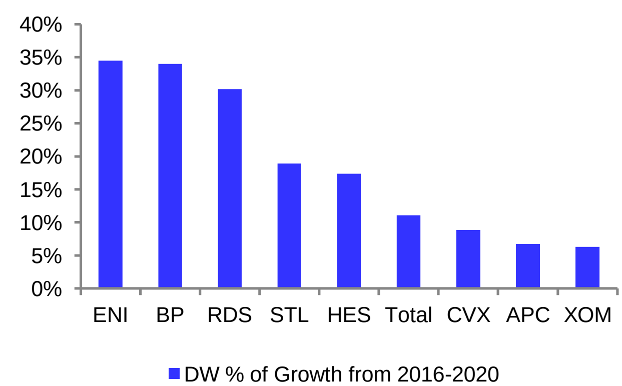
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 79: 3-Yr (2016-2019) DW Production CAGR



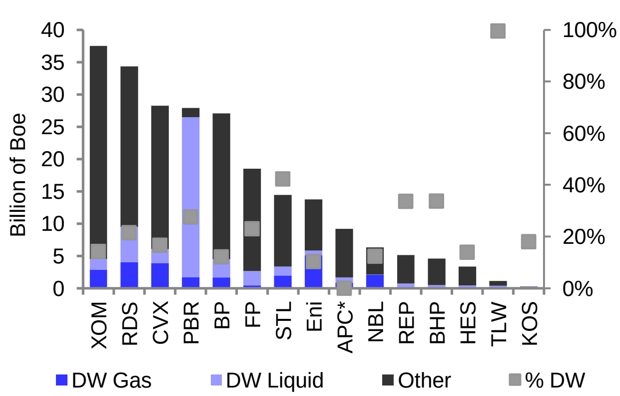
Source: Deutsche Bank, Wood Mackenzie

Figure 80: DW – % of 2016-2020 Cumulative Growth



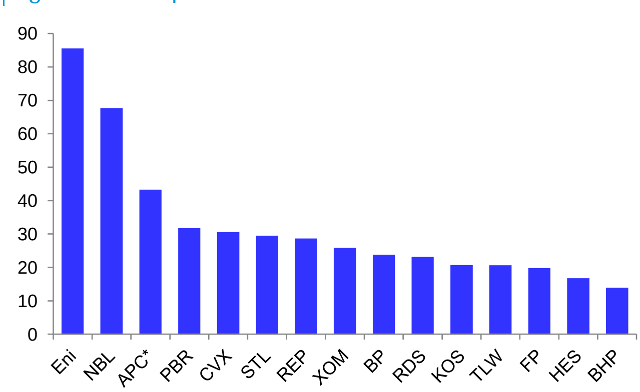
Source: Deutsche Bank, Wood Mackenzie

Figure 81: Remaining Commercial Reserves



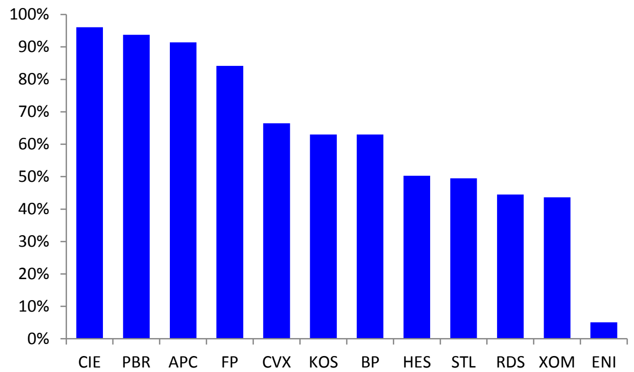
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 82: Deepwater Commercial Reserve Life



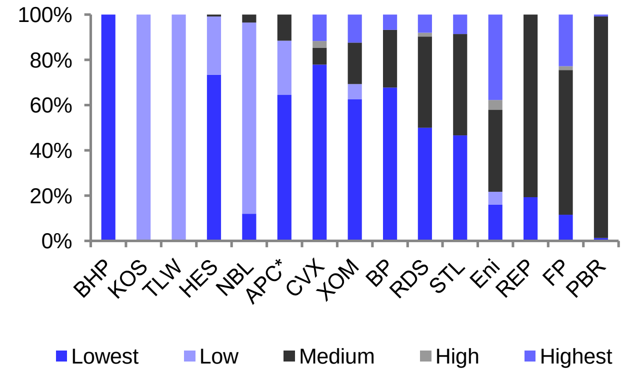
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 83: Pre-FID Deepwater Reserves Liquids Mix



Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

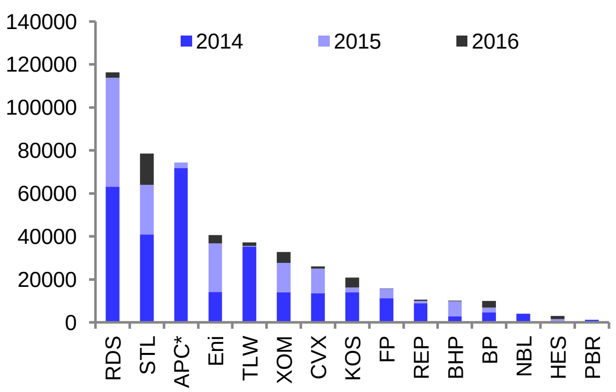
Figure 84: DW Portfolio Risk Classification (WM NPV-10 Grouped by WM Classified Country Risk)



Source: Deutsche Bank, Wood Mackenzie

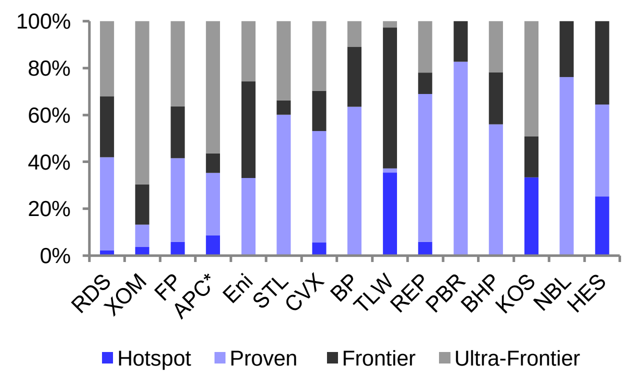
Corporate Trends in Finding Costs/Exploration and Capital Allocation

Figure 85: DW Acreage Additions (1000 sq km)



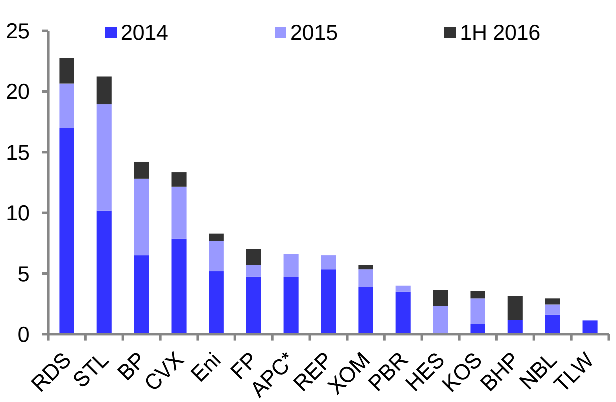
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 86: DW Exploration Acreage By Risk



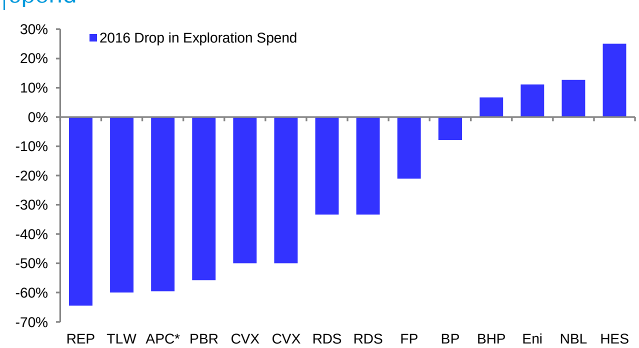
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 87: Net exploration wells by company



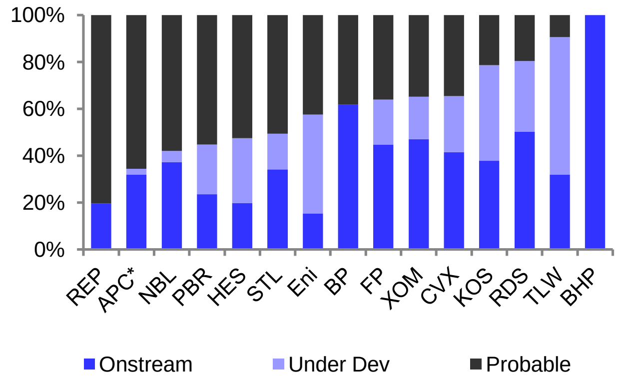
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 88: 2016 exploration budget vs. 2015 exploration spend



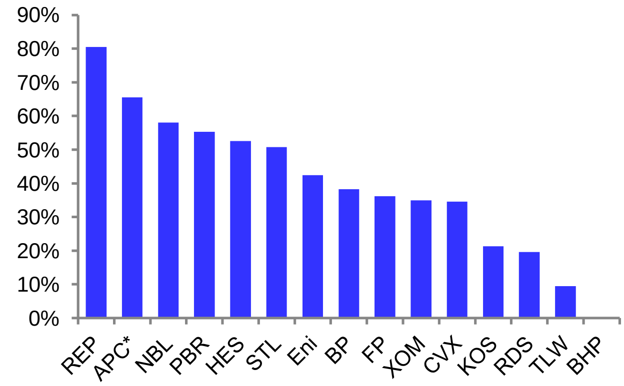
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 89: 2016-2025 Deepwater Spend by Dev Type



Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Figure 90: 2016-2025 Pre-FID % of Total DW Spend



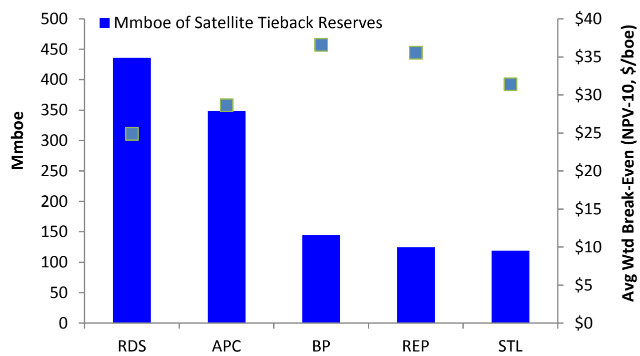
Source: Deutsche Bank, Wood Mackenzie, includes Deepwater Gas

Anadarko Petroleum

Tieback inventory to support capital discipline stewardship while Colombia & Cote d'Ivoire resources offer leverage to eventual offshore cost normalization

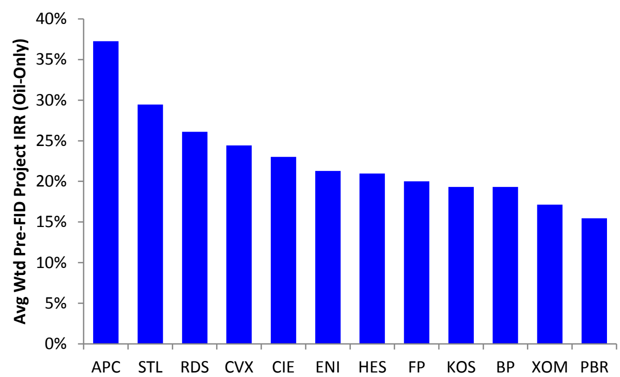
APC's announced acquisition of FCX's DW assets cemented APC's commitment to the GOM as a critical part of the company's portfolio for years to come. And while most of the large-cap E&P operators have focused on chasing the Permian "deal-flow rush", APC's announced 'doubling-up' in the Gulf of Mexico re-emphasized the flexibility that a diversified portfolio offers amidst a peer group that has become increasingly more 'independent'/onshore-weighted. And while the offshore asset base will never support the type of crude-recovery led growth momentum offered by APC's Permian assets; a sizeable tieback backlog (350 MMboe net reserves) provides flexibility toward inexpensively financed growth in its core US onshore assets.

Figure 91: Trailing only RDS, APC boasts the largest /most attractive satellite tieback inventory in the GOM



Source: Deutsche Bank, excludes under-dev and recent start-ups, reserves are net and ex in-fill drilling

Figure 92: Which underpins peer-leading returns for its deepwater pre-FID backlog



Source: Deutsche Bank, Wood Mackenzie

Figure 93: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Phobos (SE 39)	US GoM DW	175	100%	96%	2021	$25.33	$30.00	$11.17	$14.35	44%	52%
Shenandoah (WR 52)	US GoM DW	500	33%	95%	2021	$46.85	$55.10	$2.42	$4.22	18%	23%
Yeti (WR 160)	US GoM DW	100	37.50%	85%	2022	$31.34	$37.16	$8.84	$11.87	37%	46%
Yucatan (WR 95)	US GoM DW	70	25.00%	95%	2023	$33.29	$41.08	$9.55	$12.39	36%	41%
Vito*	US GoM DW	298	18.67%	90%	2022	$47.60	$56.97	$2.14	$3.78	17%	21%
Power Nap (MC 943)	US GoM DW	55	50%	78%	2024	$29.43	$33.49	$9.09	$12.01	53%	67%
Paon	Cote dIvoire	300	100.00%	100%	2020	$39.50	$47.75	$4.32	$5.91	21%	25%

*Assumes Vito developed as a standalone facility

Source: Deutsche Bank, Wood Mackenzie

Figure 94: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
Green Canyon	Warrior-1	US GoM	DW	8/1/2016	APC	APC* (55%), Ecopetrol (15%), JX Nippon Oil & Energy Corp (15%), Mitsubishi Corporation (15%)	Following drilling operations at Shenandoah, the Warrior prospect will spud, targeting Miocene sands equivalent in age to the nearby K2 field.
Shenandoah	Shendandoah-6	US GoM	UDW	2H16	APC	APC* (30%), COP (30%), CIE (20%), MRO (10%), Venari Resources (10%)	The Shendandoah-6 appraisal well will spud before year end. The well is expected to establish the oil-water contact on the eastern flank of the field and quantify the full resource potential.
Purple Angle	Purple Angel-1	Colombia	UDW	10/1/2016	APC	APC* (100%)	An exploration well is planned for the 2H16 on the Purple Angel block. The well is designed to test objectives similar to those at the Kronos discovery.
Block CI-103	Paon-3AR ST	Cote d`Ivoire	UDW	4/17/2016	APC	APC* (65%), Mitsubishi Corporation (20%), PETROCI (15%)	Following the success of the Paon-5A horizontal well, the company successfully drilled its second deepwater horizontal well at the Paon-3AR sidetrack encountering approximately 120 net feet TVT of pay.
Block CI-528	Rossignol -1	Cote d`Ivoire	UDW	8/1/2016	APC	APC* (90%), PETROCI (10%)	A two-well exploration campaign is planned to commence in 3Q16 after the completion of the Paon appraisal program. Located to the southeast of Paon, the Rossignol and Pelican prospects will target similar-aged sands along trend to the Paon discovery.
Block CI-528	Pelican-1	Cote d`Ivoire	UDW	10/1/2016	APC	APC* (90%), PETROCI (10%)	--
WR/51, West Gulf Coast	WR 51 #4 (G31938)	US GoM	UDW	3/14/2016	APC	APC* (30%), COP (30%), CIE (20%), MRO (10%), Venari Resources (10%)	--
MC/977, East Gulf Coast	Haleakala-1	US GoM	DW	6/1/2017	APC	APC* (33.34%), Ecopetrol (25%), Murphy Oil (25%), W & T Offshore (16.66%)	--
DC/853, East Gulf Coast	Opal-1	US GoM	UDW	1/1/2017	APC	APC* (50%), Murphy Oil (50%)	--

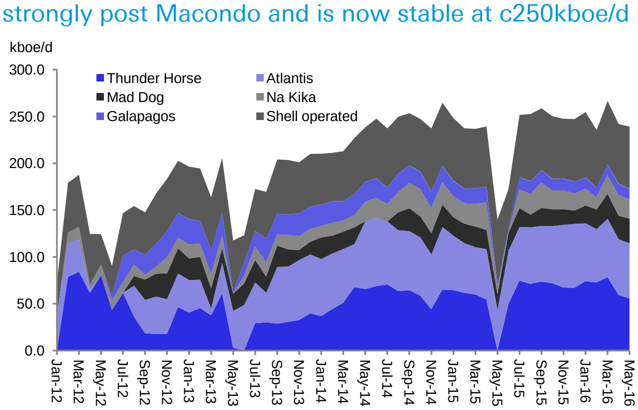
Source: Deutsche Bank, Wood Mackenzie

BP

Absolutely core to its future despite nearly breaking its heart

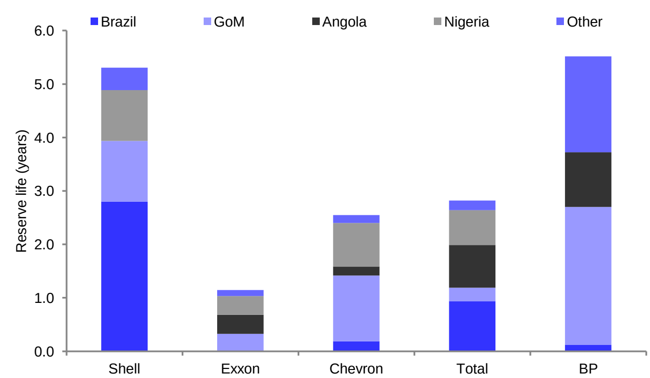
Macondo may have almost broken the company and it has certainly encouraged BP to think more about the balance of discipline and geography across its portfolio. But the DW remains an absolutely key source of competitive advantage for BP. A leading player in the US GoM and Angola, the DW continues to represent around 20% of BP's overall production adding significant leverage to its cash flows. With over 80% of its GoM resource yet to be produced out BP envisages an enduring future in this key play, and by virtue of its decision to focus its efforts around its key four hubs (Thunder Horse, Atlantis, Mad Dog and Na Kika) one that we suspect will deliver excellent returns and, perhaps unexpectedly, production stability into the medium term. Growth is likely to come from the build out of Mad Dog 2 and, longer term, its interest in discoveries to be developed by Chevron (Tiber, Gila, Gibson). In Angola, we see the outlook for production and cash flow as far more contingent on an improvement in fiscal and local content terms, with 2016 production of c200kboe/d expected to move into decline as we move towards the later stages of the decade. Exploration success, not least in Block 31 offers the opportunity for future growth but progress here is unlikely absent a change in fiscal terms and local content requirements.

Figure 95: The US GoM: Production has recovered strongly post Macondo and is now stable at c250kboe/d



Source: Deutsche Bank, excludes underdevelopment and recent start-ups, reserves are computed on a net basis and exclude in-fill drilling opportunities

Figure 96: BP's DW resource base represents a significant proportion of its 19 year 2P resource base



Source: Deutsche Bank

Figure 97: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Block 18 West	Angola	150	50%	100%	2021	$66.64	$75.80				12%
Block 31 Southeast	Angola	541	27%	100%							
Block 31 West	Angola	448	27%	100%							
Guadalupe (KC 10)	United States	300	43%	92%	2023	$55.12	$64.88	$0.82	$2.50	13%	18%
Itaipu	Brazil	154	40%	93%	2022	$26.09	$29.12				9%
Kaskida (KC 292)	United States	329	100%	92%	2024	$52.70	$62.06	$1.10	$2.59	14%	19%
Leda	Angola	202	27%	100%	2024						
Orca	Angola	401	30%	100%	2022	$42.96	$53.67	$1.49	$2.31	17%	21%
Tiber (KC 102)	United States	554	41%	88%	2022	$45.11	$53.04	$2.33	$3.83	19%	25%
West Med Deepwater	Egypt	387	83%	0%	2023						
Mad-Dog II	United States	500	61%	96%	2022	$43.70	$52.04	$2.60	$4.14	20%	25%

Source: Deutsche Bank, blue-lighted metrics represent Wood Mackenzie estimates

Figure 98: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
PEP 54863, Great South	PEP 54863 Shell well-1	New Zealand	DW	4/1/2017	RDS	Shell* (59%), OMV (26%), Mitsui & Co (15%)	--
AC/P 52. Browse Basin	Cronus-1	Australia	DW	10/1/2016	RDS	Shell* (50%), Sasol (30%), Finder Exploration (20%)	--
WR/376, West Gulf Coast	Ipanema-1	US GoM	UDW	10/1/2016	RDS	Shell* (100%)	--
EL 2424, Scotian Shelf	Monterey Jack-1	Canada	UDW	11/1/2016	RDS	Shell* (50%), COP (30%), Suncor Energy (20%)	--
Block-1	--	Rovuma Basin, Tanzania	Shelf - UDW	2H16	RDS	Shell (60%), Ophir Energy (20%), Pavillion Energy (20%)	Ophir will participate in a 2 well program later this year offshore Tanzania, operated by Shell. This will comprise 1 deepwater well in Block-1 and another in Block-4, both targeting further gas close to the planned location of subsea development infrastructure, and which could be tied back easily, thereby improving the economics of any potential development
Block-4	--	Tanzanian Coastal	DW	2H16	RDS	Shell (60%), Ophir Energy (20%), Pavillion Energy (20%)	
OPL 245, Niger Delta	OPL 245-1	Nigeria	UDW	1/1/2017	Eni	Eni* (50%), Shell (50%)	--
GB/998, West Gulf Coast	GB 998 #1 (G31688)	US GoM	DW	6/10/2016	CVX	CVX* (37.50%), Shell (37.50%), COP (25%)	--

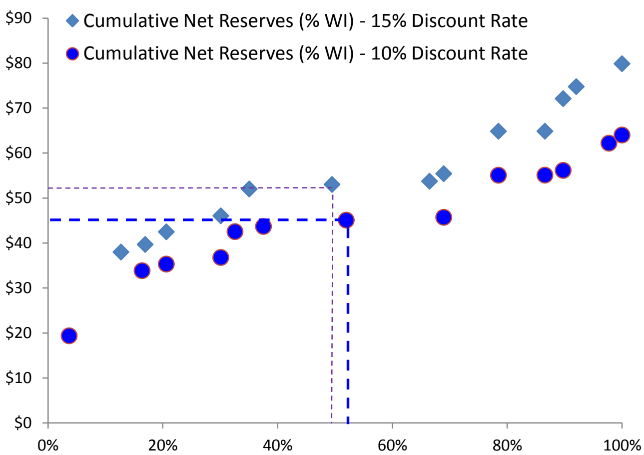
Source: Deutsche Bank, Wood Mackenzie

Chevron

With material exposure to GoM and an accelerated roll-off in UDW contracts, CVX is well-positioned to capitalize on evolving deflationary cost trends

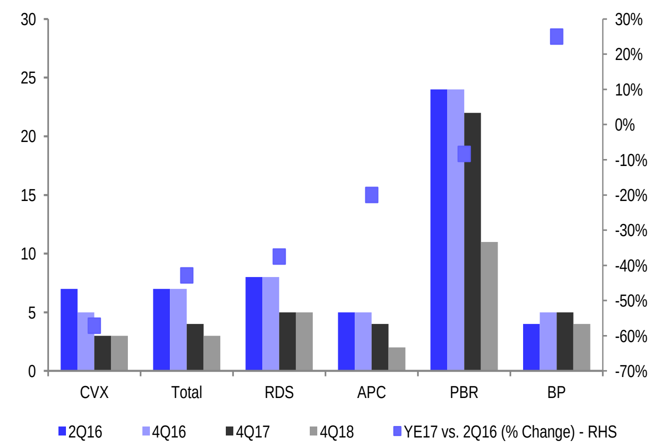
With significant leverage to the 'costlier to develop' UDW GoM (~75% of CVX's net oil-wtd deep-water reserves) and a relatively sharper drop in committed UDW drill-ships (~60% vs. current levels) through YE17 we see CVX as relatively well positioned vs. peers to capitalize on deflationary cost trends. In a normalized cost environment, we see ~50% of CVX's pre-FID resource 'break-even' at $45/$52 (NPV-10, NPV-15 resp) per bbl, providing the impetus for what we regard as the highest rate of change in portfolio economics into a normalizing offshore cost environment.

Figure 99: We see ~50% of CVX's new DW projects 'break-even' at $45/$52 (10%, 15% DR in a normalized offshore cost environment



Source: Deutsche Bank, Wood Mackenzie, % of net reserves

Figure 100: And with 60% fewer UDW rig commits by YE17, CVX is relatively well-positioned to capitalize on deflationary cost trends vs. peers



Source: Deutsche Bank, IHS

Figure 101: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
Pre-FID						10%	15%	$60	$70	$60	$70
Anchor (GC 807)	United States	475	56%	92%	2022	$45.73	$53.76	$2.51	$4.22	19%	24%
Bonga SW	Nigeria	900	17%	88%	2023	$40.25	$52.15	$2.07	$3.13	18%	22%
Cambo	United Kingdom	120	33%	90%	2027	$42.55	$55.44				20%
Guadalupe (KC 10)	United States	300	43%	92%	2023	$55.12	$64.88	$0.82	$2.50	13%	18%
Lochnagar	United Kingdom	125	40%	100%	2024	$56.17	$72.12				14%
Rosebank	United Kingdom	314	40%	93%	2024	$62.22	$79.89				11%
Sicily (KC 814)	United States	300	50%	92%	2025	$55.10	$64.87	$0.75	$2.28	13%	18%
Uge	Nigeria	171	21%	63%	2025	$72.03	$84.09	-$1.96	-$0.33	4%	9%
Mad-Dog II	United States	500	16%	96%	2022	$43.70	$52.04	$2.60	$4.14	20%	25%
Tahiti Vertical Expansion*	United States	100	58%	92%	2022	$19.39	$22.51	$13.09	$16.28	74%	87%

Source: Deutsche Bank, blue-lighted metrics represent Wood Mackenzie estimates

Figure 102: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
GC/719, West Gulf Coast	Gator Lake-1	US GoM	DW	12/1/2016	CVX	CVX* (75%), Venari Resources (25%)	--
GB/998, West Gulf Coast	GB 998 #1 (G31688)	US GoM	DW	6/10/2016	CVX	CVX* (37.50%), Shell (37.50%), COP (25%)	--
KC/10, West Gulf Coast	Guadalupe-3	US GoM	DW	8/1/2016	CVX	CVX* (42.50%), BP (42.50%), Venari Resources (15%)	--
Block 42	--	Suriname	Shelf - UDW	3Q16	KOS	KOS* (33.34%), CVX (33.33%), HES (33.33%)	Positive read-through from the Liza discovery and its successful follow-up appraisal in Suriname was confirmed by the recent farm-out of Block 42 to HES. KOS will acquire a new 3D seismic survey in 3Q16 with a view to drilling up to two wells starting late 2017 or early 2018. Play extension of proven oil province, key prospects with play diversity testing 1+ BBbls potential with multi-billion barrel dependent follow-on opportunity at Anapai, Aurora. 11,000 km2 position, equivalent to ~475 GoM blocks.

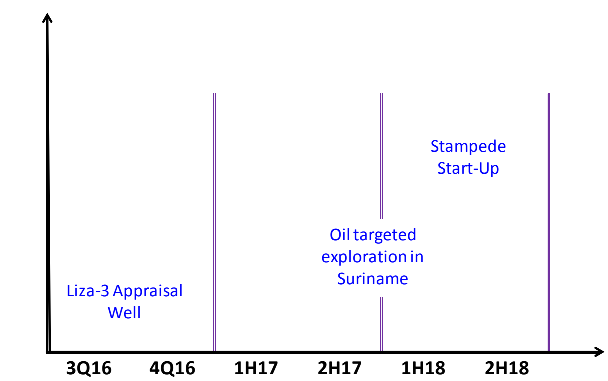
Source: Deutsche Bank, Wood Mackenzie

Hess

All Eyes on Liza, For Now

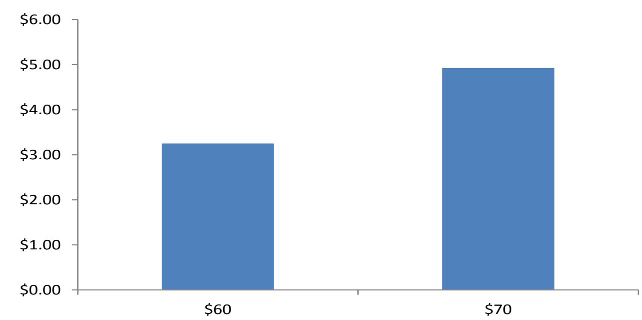
Beyond some marginal field development opportunities in Ghana, HES' Pre-FID inventory value is chiefly tied to the development time-line of XOM's Liza prospect with upside from potential exploration success in the Stabroek License in Guyana and Block 42, Suriname, where oil-focused drilling likely by late 2017/early 2018. With a dry-hole at the XOM operated Skipjack prospect in 3Q, investor focus has now shifted to results at the Liza-3 appraisal well that was spud this September. We estimate ~ $3.25/sh, $5/sh of value at $60/$70/bbl Brent resp for HES' stake in Liza.

Figure 103: Key DW Time-Line Dates for HES



Source: Deutsche Bank, Wood Mackenzie

Figure 104: DBe HES Liza Valuation ($/sh)



Source: Deutsche Bank,

Figure 105: Pre-FID List of Major Oil Development Projects

Field	Country	Basin	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price			NPV-10 ($/boe)		IRR	
							10%	15%		$60	$70	$60	$70
Beech	Ghana	Cote d`Ivoire	82	40%	78%	1/1/2028	$30.93	$39.84					24%
Liza	Guyana	Guyana	1100	30%	100%	1/1/2021	$42.00	$53.00	#	$3.12	$4.73	18%	21%
Paradise	Ghana	Cote d`Ivoire	133	40%	34%	1/1/2028	$43.93	$61.45					15%
Pecan	Ghana	Cote d`Ivoire	90	40%	100%	1/1/2025	$53.68	$64.17					14%
Sicily (KC 814)	United States	West Gulf Coast Tertiary	300	25%	92%	1/1/2025	$55.10	$64.87	#	$0.75	$2.28	13%	18%

Source: Deutsche Bank, Wood Mackenzie

Figure 106: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
Block 42	--	Suriname	Shelf - UDW	3Q16	KOS	KOS* (33.34%), CVX (33.33%), HES (33.33%)	Positive read-through from the Liza discovery and its successful follow-up appraisal in Suriname was confirmed by the recent farm-out of Block 42 to HES. KOS will acquire a new 3D seismic survey in 3Q16 with a view to drilling up to two wells starting late 2017 or early 2018. Play extension of proven oil province, key prospects with play diversity testing 1+ BBbls potential with multi-billion barrel dependent follow-on opportunity at Anapai, Aurora. 11,000 km2 position, equivalent to ~475 GoM blocks.
Liza, Stabroek Block	Liza-3	Offshore Guyana	UDW	9/1/2016	XOM	XOM* (45%), HES (30%), Nexen (25%)	Liza-3 well spud in Sep 2016. Following the Skipjack well, the operator intends to drill a third well at Liza to further appraise the discovery. Four wells to further explore Liza and the Stabroek Block planned in 2016
CA1, Baram Delta	Ranger-1	Brunei Darussalam	UDW	1/1/2017	XOM	XOM* (45%), HES (30%), Nexen (25%)	--
Tubular Bells (MC 725)	--	US GoM	DW	6/15/2016	HES	HES (57.14%), CVX (42.86%),	5th production well at Tubular Bells was spud mid-June 2016, and is scheduled to be brought online in early 2017, HES anticipates starting water injection in 3Q16.
CA1, Baram Delta	CA1 Total well	Brunei Darussalam	DW	10/1/2016	Total	Total* (54%), BHP Billiton (22.50%), HES (13.50%), Murphy Oil (5%), Petronas Carigali (5%)	--
Offshore Nova Scotia	--	Canada Offshore	Shelf - UDW	2Q18	BP	BP* (50%), HES (40%), Woodside Petroleum (20%)	Post finalization of well locations and completion of environmental impact assessment, first well planned in 2Q18. 3.5 MM acres spread over ~ 600 GoM blocks having multiple leads in sub-salt play. GoM analogue trap styles with oil prone, Cretaceous reservoirs.

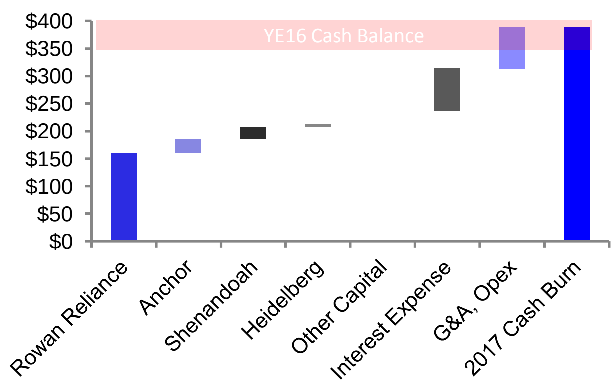
Source: Deutsche Bank

Cobalt International Energy

A Levered (And Then Some) Play on UDW GoM Cost Normalization

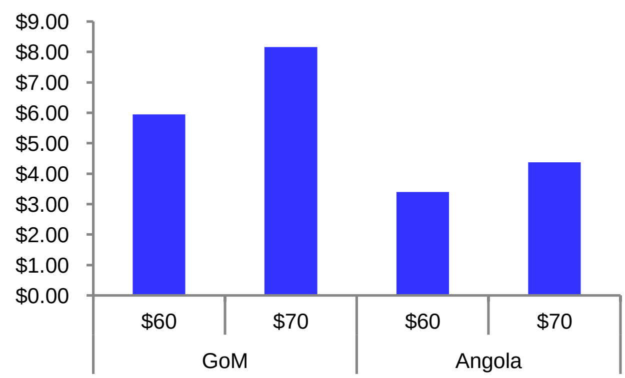
With an announced early termination of its Rowan Reliance UDW drill-ship contract early next year (following final North Platte appraisal activity) and a targeted imminent sale-down of its Angola DW assets (anticipated within 3-6 months), asset-level updates on evolving project economics and development time-lines will likely take a back seat to addressing the company's liquidity concerns ahead of the maturity of its 2019 convertibles (~$1.38Bn). However, while the near-term focus remains on managing near-term liquidity concerns, CIE's Lower-Tertiary GoM portfolio offers relatively attractive leverage to evolving offshore cost deflation trends longer-term if the company is able to execute through the near-term headwinds. With viability of the company effectively depending on successful monetization of its Angola position, as well as one of either Anchor/Shenandoah in 2017, CIE has significant leverage to a modest recovery in the market value of underlying DW resource.

Figure 107: Managing liquidity concerns to be the focus in 2017



Source: Deutsche Bank

Figure 108: CIE Asset-Level Valuations ($/sh) –ex Debt



Source: Deutsche Bank

Figure 109: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Anchor (GC 807)	United States	475	20%	92%	2022	$45.73	$53.76	$2.51	$4.22	19%	24%
North Platte (GB 959)	United States	475	60%	92%	2021	$45.74	$53.75	$2.76	$4.64	19%	24%
Shenandoah (WR 52)	United States	500	20%	95%	2021	$46.85	$55.10	$2.42	$4.22	18%	23%
Yucatan (WR 95)	United States	70	5%	90%	2022	$47.60	$56.97 #	$2.14	$3.78	17%	21%
Orca (ex Lontra)	Angola	500	40%	100%	2022	$42.96	$53.67	$1.49	$2.31	17%	21%
Cameia	Angola	596	40%	100%	2020	$39.87	$49.56	$2.09	$2.94	19%	23%

Source: Deutsche Bank, Wood Mackenzie

Figure 110: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
North Platte (GB 959)	North Platte-5	US GoM	DW	10/1/2016	CIE	CIE* (60%), Total (40%)	CIE will commence drilling in North Platte Number 4 appraisal well in 3Q16. North Platte Number 4 is designed to further delineate the North Platte Inboard Lower Tertiary reservoir. Rock and the reservoir properties compare favorably to properties seen in the Miocene reservoirs in the Gulf.
Shenandoah	Shendandoah-6	US GoM	UDW	2H16	APC	APC* (30%), COP (30%), CIE (20%), MRO (10%), Venari Resources (10%)	The Shendandoah-6 appraisal well will likely spud before YE2016. The well is expected to establish the oil-water contact on the eastern flank of the field and quantify the full resource potential.

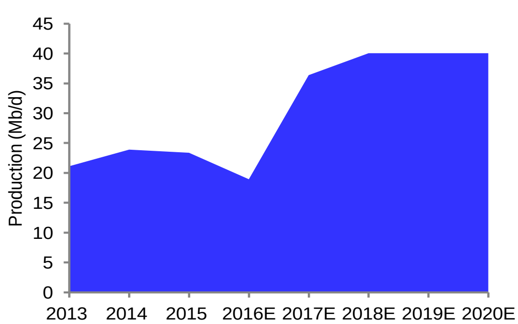
Source: Deutsche Bank

Kosmos Energy

Quality leverage to deepwater oil, with material potential catalysts through '18

With 100% of its current production coming from deepwater Ghana, and a robust portfolio of both discovered and yet-to-be-developed DW resource (Greater Tortue) and potentially high impact exploration (Mauritania, Senegal, Suriname and Sao Tome), only CIE offers comparable "pure" leverage to the deepwater. With the successful recent start-up of TEN (targeted ramp to full capacity by YE16), the base case, or downside support, for KOS is both unique and robust: a self-funded exploration program, with significant liquidity ($1.2 Bn), stable production, and a fully-funded, cash neutral outlook at ~$50/bbl. Upside potential remains significant, however, as the potential farm-down of its ~25 Tcf Greater Tortue gas discovery in Mauritania/Senegal (targeting YE16) could begin to derisk what we see as $7-$10+/sh of value. Further, with a material, continuous exploration program beginning in mid-2017 (Mauritania/Senegal) followed by Suriname (late 17/18) and Sao Tome (2018), we see many shots on goal offering potential support should the environment continue to improve.

Figure 111: Stable production/CF through 2020+



Source: Deutsche Bank, Company data

Figure 112: YUUUGE potential value at Greater Tortue

	Gross Resource Size (Tcf)				
Value ($/mcfe)	5	10	15	25	35
$0.20	1.57	3.15	4.72	7.87	11.02
$0.25	1.97	3.94	5.91	9.84	13.78
$0.30	2.36	4.72	7.09	11.81	16.54
$0.35	2.76	5.51	8.27	13.78	19.29
$0.40	3.15	6.30	9.45	15.75	22.05
$0.45	3.54	7.09	10.63	17.72	24.80

Source: Deutsche Bank,

Figure 113: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Block C-8	Mauritania	1623	90.00%	0%		$0.00	$0.00	$0.00	$0.00	0%	0%
Greater Jubilee	Ghana	55	30.00%	91%	1/1/2020	$46.85	$55.10	$2.42	$4.22	18%	23%

Source: Deutsche Bank, Wood Mackenzie

Figure 114: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
St Louis Offshore Profond, Senegal - Bove	South Senegal -1	Senegal	DW	1/1/2017	KOS	KOS* (60%), Timis Corp (30%), Petrosen (10%)	--
St Louis Offshore Profond, Senegal - Bove	South Senegal -2	Senegal	DW	3/1/2017	KOS	KOS* (60%), Timis Corp (30%), Petrosen (10%)	--
Block 42	--	Suriname	Shelf - UDW	3Q16	KOS	KOS* (33.34%), CVX (33.33%), HES (33.33%)	Positive read-through from the Liza discovery and its successful follow-up appraisal in Suriname was confirmed by the recent farm-out of Block 42 to HES. KOS will acquire a new 3D seismic survey in 3Q16 with a view to drilling up to two wells starting late 2017 or early 2018. Play extension of proven oil province, key prospects with play diversity testing 1+ BBbls potential with multi-billion barrel dependent follow-on opportunity at Anapai, Aurora. 11,000 km2 position, equivalent to ~475 GoM blocks.
Blocks 6, 11 & 12 - Rio Munni Basin	--	Offshore Sao Tome	Shelf - UDW	1Q17	KOS (Blocks 11 & 12), Galp Energia (Block 6)	**Block 6** - Galp Energia* (45.00%), KOS (45.00%), Gov. of Sao Tomé/Principe (10.00%) **Block 11** - KOS* (85.00%), Gov of Sao Tomé/Principe (15.00%) **Block 12** - KOS* (65.00%), Equator Exploration (22.50%), Gov of Sao Tomé/Principe (12.50%)	KOS is planning a new 3D seismic survey in the Rio Muni Basin petroleum system, expected to commence in Jan 2017 covering 13,000 km2, which will be the largest 3D seismic survey in KOS's history and one of the largest single 3D seismic surveys ever acquired offshore West Africa.

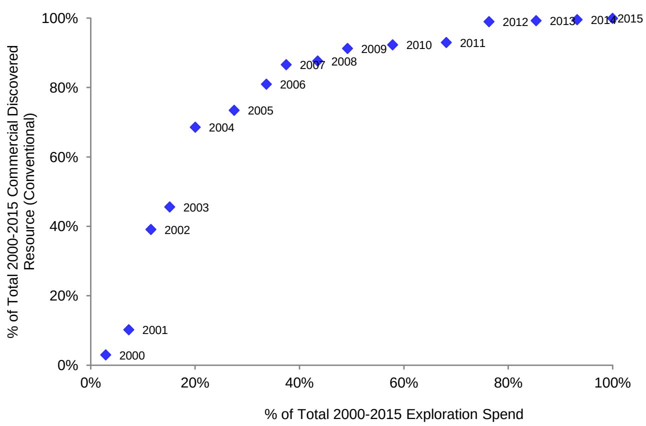
Source: Deutsche Bank

Murphy Oil

Looking Back Through the Rearview?

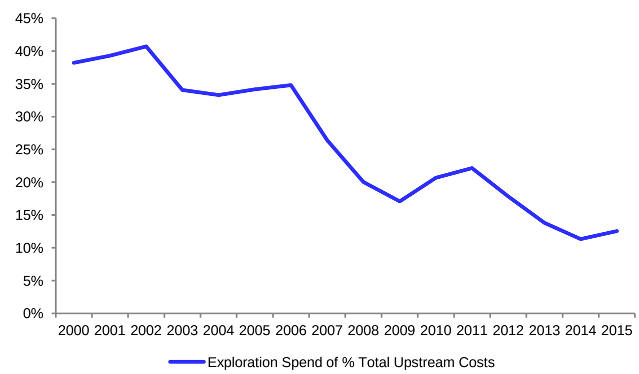
Once one of the more active exploration names in our coverage universe, a combination of value destruction via the drill-bit and a constrained spend profile (made more so by increased capital allocation to unconventional North America assets in the Eagle Ford and Montney/Duvernay) has resulted in a shift to small-scale 'infrastructure-driven' exploration in the US GoM (i.e. Kodiak, Dalmation). With an oil-weighted pre-FID backlog consisting of a modest stake (~8%) in Total's operated Jagus/Julong fields (~200 MMboe of WM est cumulative gross resource) off Brunei, we expect medium-term focus to remain on identifying potential small-scale tieback prospects though we understand that MUR is currently considering a potential participation in a bid process in Brazil which could certainly bring the deepwater back into focus.

Figure 115: Post Kikeh/Kakap discoveries, Murphy has struggled to add reserves via conventional exploration



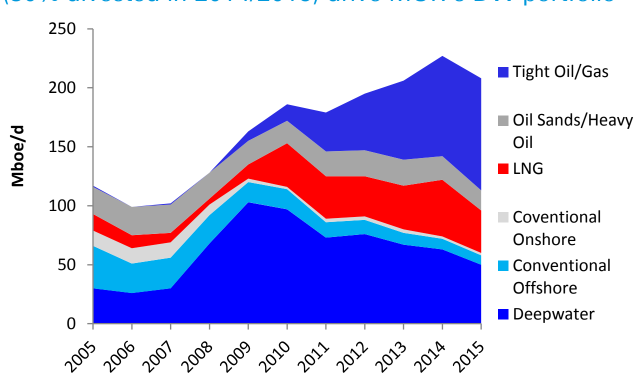
Source: Deutsche Bank, Wood Mackenzie

Figure 116: A lack of exploration success alongside an increased focus on its unconventional resource has significantly scaled back exploration spend



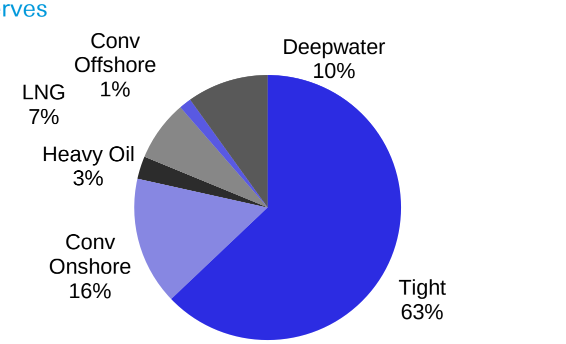
Source: Deutsche Bank, Wood Mackenzie

Figure 117: Maturing assets in both GoM and Malaysia (30% divested in 2014/2015) drive MUR's DW portfolio



Source: Deutsche Bank, Wood Mackenzie

Figure 118: And represent ~10% of current recoverable reserves



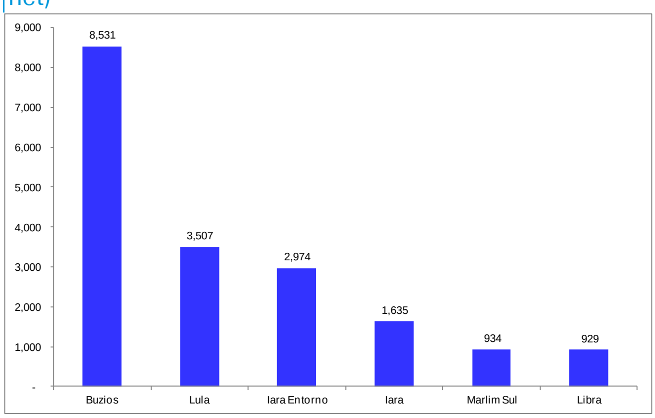
Source: Deutsche Bank, Wood Mackenzie

Petrobras

Global leader in DW and UDW output with substantial reserves base and an ambitious development programme

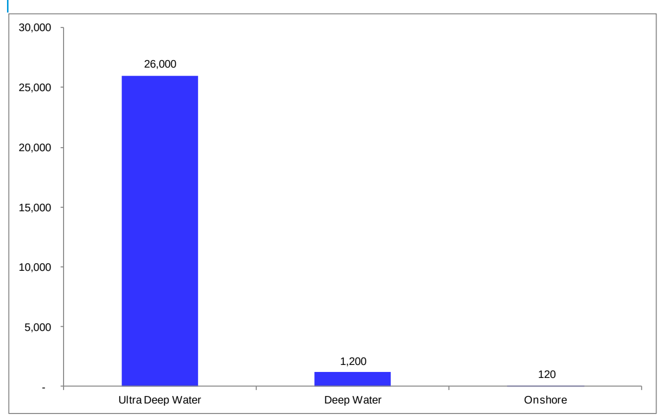
Petrobras is the global leader in DW and UDW production, operating more output (on boe basis) than any other oil company. DW/UDW output accounts for approximately 80% of Petrobras's domestic production. As of YE15, Petrobras had total SEC proved reserves of 10.5bnboe, of which we estimate over 90% is accounted for by DW/UDW fields. Between 2013-18 PBR will have commissioned DW/UDW production units with total nominal production capacity of 3.12mnbpd. The majority of its future WI production comes from Assignment Agreement (aka Transfer of Rights) acreage, the exact fiscal terms of which are yet to be determined, but which should provide Petrobras with an estimated upfront IRR of 8.83%.

Figure 119: Petrobras: total recoverable reserves estimates for the largest DW and UDW fields (mnboe, net)



Source: WoodMackenzie

Figure 120: Petrobras: average flow rates,



Source: Company data

Figure 121: Pre-FID List of Major Oil Development Projects (Note that TOR fields- those for which economics are not listed below, PBR's returns are capped at 8.83%)

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
BM-C-33	Brazil	1516	30%	65%	2024	$48.79	$71.27				15%
Buzios (Surplus)	Brazil	4862	100%	94%	2028	$36.53	$42.26				9%
Carcara	Brazil	980	0%	78%	2023	$35.79	$45.59	$2.78	$3.92	21%	25%
Iara Entorno (Surplus)	Brazil	1775	100%	94%	2025	$38.31	$50.64				9%
Itapu	Brazil	400	100%	93%	2022	$26.09	$29.12				9%
Itapu (Surplus)	Brazil	307	100%	94%	2030	$33.07	$51.16				9%
Libra*	Brazil	5104	40%	100%	2021	$46.34	$58.23	$1.65	$2.50	16%	18%
Sepia	Brazil	364	100%	93%	2020	$25.44	$27.22				9%
Sepia (Surplus)	Brazil	429	100%	94%	2026	$43.65	$52.57				9%
Sepia Leste	Brazil	119	80%	94%	2027	$37.76	$41.21				9%
Sul de Lula	Brazil	109	100%	91%	2026	$34.19	$39.42				9%
Sul de Sapinhoa	Brazil	252	100%	100%	2026	$36.24	$39.88				9%

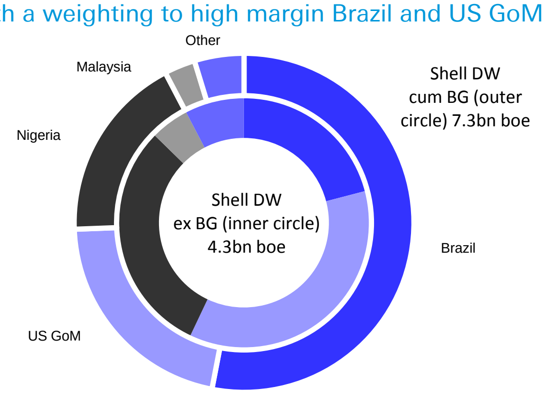
Source: Deutsche Bank, blue-lighted metrics represent Wood Mackenzie estimates

Royal Dutch Shell

Through its acquisition of BG Shell has put the DW at the heart of strategy

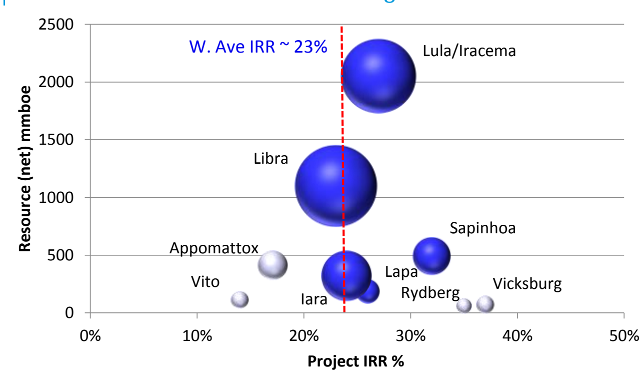
Shell has long seen the deepwater as key to its ability to source resource for growth and return. Already a leading deepwater player with operations in more DW geographies than near any of its IOC peers, the acquisition of BG has transformed its potential and importantly, the outlook for growth at least through the early 2020s. Already boasting a strong position in the US GoM, not least following the discovery of over 1bn barrels in the Norphlets (Appomattox, Rydberg, Vicksburg, etc) the addition of at least 4bn boe of low-breakeven resource in Brazil's Santos Basin is expected to see DW production rise towards 1mboe/d by 2020 from nearer 600kboe/d today. Moreover, as a basin in its infancy we suspect that in much the same way that the US GoM has proven a source of opportunity for at least the past two decades so too do we believe that thorugh improved recovery and incremental exploration success Brazil alone will prove a basin that the company can feed on for multiple years.

Figure 122: The deepwater opportunity: Post BG c7bn boe with a weighting to high margin Brazil and US GoM



Source: Deutsche Bank, excludes underdevelopment and recent start-ups, reserves are computed on a net basis and exclude in-fill drilling opportunities

Figure 123: At $70/bbl we see the potential for c$50bn of investment to 2030 with an average IRR of c23%



Source: Deutsche Bank

Figure 124: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Bolia-Chota	Nigeria	446	32%	76%	2030	$56.80	$73.90	$0.19	$0.72	11%	14%
Kaikias (MC 768)	United States	147	100%	79%	2019	$22.68	$25.58	$10.09	$13.14	48%	61%
Libra	Brazil	5104	20%	100%	2021	$46.34	$58.23	$1.65	$2.50	16%	18%
Limbayong	Malaysia	252	27%	48%	2025	$44.93	$70.76				15%
Power Nap (MC 943)	United States	55	50%	78%	2024	$29.43	$33.49	$9.09	$12.01	53%	67%
Rydberg (MC 525)	United States	100	57%	84%	2025	$27.66	$32.73	$9.76	$12.45	53%	61%
Vito (MC 984)	United States	298	51%	90%	2022	$47.60	$56.97	$2.14	$3.78	17%	21%
Yucatan (WR 95)	United States	70	42%	95%	2023	$33.29	$41.08	$9.55	$12.39	36%	41%

Source: Deutsche Bank, blue-lighted metrics represent Wood Mackenzie estimates

Figure 125: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
Liza, Stabroek Block	Liza-3	Offshore Guyana	UDW	9/1/2016	XOM	XOM* (45%), HES (30%), Nexen (25%)	Liza-3 well spud in Sep 2016. Following the Skipjack well, the operator intends to drill a third well at Liza to further appraise the discovery. Four wells to further explore Liza and the Stabroek Block planned in 2016
CA1, Baram Delta	Ranger-1	Brunei Darussalam	UDW	1/1/2017	XOM	XOM* (45%), HES (30%), Nexen (25%)	--
Neptun Deep	Flamingo-B	Black Sea, Romania	DW	8/1/2016	XOM	XOM* (50%), OMV Petrom (50%)	--
Neptun Deep	Lopatar-2	Black Sea, Romania	UDW	8/1/2016	XOM	XOM* (50%), OMV Petrom (50%)	--
LB- 13, Liberia Basin	Mesurado-1	Liberia	UDW	1/1/2017	XOM	XOM* (83%), Canadian Overseas Petroleum (17%)	--
Area 14, Punta Del Este	Raya-1	Uruguay	UDW	3/30/2016	Total	Total* (50%), XOM (35%), Statoil (15%)	--

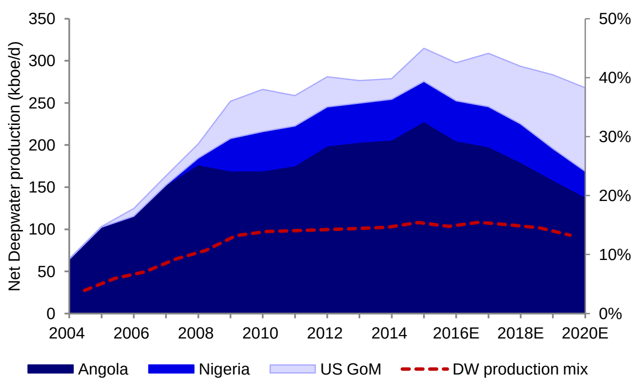
Source: Deutsche Bank, Wood Mackenzie

Statoil

A bias to conventional, but deepwater an increasing driver of growth

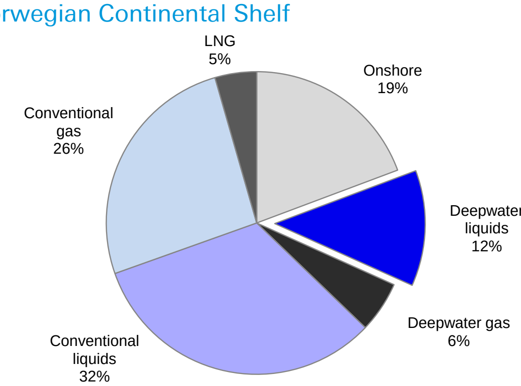
Statoil may be the largest offshore operator in the world, but unlike its European peers this exposure is weighted heavily towards conventional offshore and not the deepwater. That is not to say that deepwater is not meaningful for Statoil. At ~15% of group production and ~12% of the resource base the numbers are not inconsequential. Legacy positions in the West African nations of Angola (~200kb/d) and Nigeria (~50kboe/d) dominate but appear largely void of opportunity and in inexorable decline. More encouraging are positions in the US GoM (45kboe/d rising to 100kboe/d) and Brazil, where the recent acquisitions at Carcara (~750mmbbls liquids in the Santos pre-salt) and BM-C-33 (~1bn bbls liquids in the Campos) will do much to support growth post 2020.

Figure 126: Statoil's deepwater portfolio comprises legacy positions in West Africa with growth in GoM (pre-2020) and Brazil (post-2020 and not shown below)



Source: Deutsche Bank, Wood Mackenzie

Figure 127: At 12% of commercial resources, deepwater is dwarfed by Statoil's conventional offshore footprint on the Norwegian Continental Shelf



Source: Deutsche Bank, Wood Mackenzie, Note: Resources exclude Tanzania Deepwater gas as we consider this sub-commercial at Deutsche price deck

Figure 128: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
BM-C-33	Brazil	1516	35%	65%	2024	$48.79	$71.27	$0.00	$0.00	0%	15%
Bay du Nord	Canada	300	65.00%	100%	2025						
Block 31 Southeast	Angola	541	13%	100%							
Block 31 West	Angola	448	13.33%	100%							
Harpoon	Canada	100	65.00%	100%	2028						
Leda	Angola	202	13.33%	100%	2024						
Mizzen North	Canada	130	65%	100%	2030						
Power Nap (MC 942)	United States	55	100.00%	78%	2024	$29.43	$33.49	$9.09	$12.01	53%	67%
Vito (MC 984)	United States	298	30.00%	90%	2022	$47.60	$56.97	$2.14	$3.78	17%	21%
Yeti (WR 160)	United States	100	50.00%	85%	2022	$31.34	$37.16	$8.84	$11.87	37%	46%
Tahiti Vertical Expansion*	United States	100	25.00%	92%	2022	$19.39	$22.51	$13.09	$16.28	74%	87%
Carcara	Brazil	980	66.00%	78%	2023	$35.79	$45.59	$2.78	$3.92	21%	25%

Source: Deutsche Bank, blue-lighted metrics represent Wood Mackenzie estimates

Figure 129: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
EL 1126, Jeanne d`Arc	Fitzroya A-12Z	Canada	DW	2/11/2016	Statoil	Statoil* (50%), CVX (40%), BG (10%)	--
EPP-37, Great Australian Bight	Stromlo-1	Australia	UDW	12/31/2016	BP	BP* (70%), Statoil (30%)	--
Area 14, Punta Del Este	Raya-1	Uruguay	UDW	3/30/2016	Total	Total* (50%), XOM (35%), Statoil (15%)	--

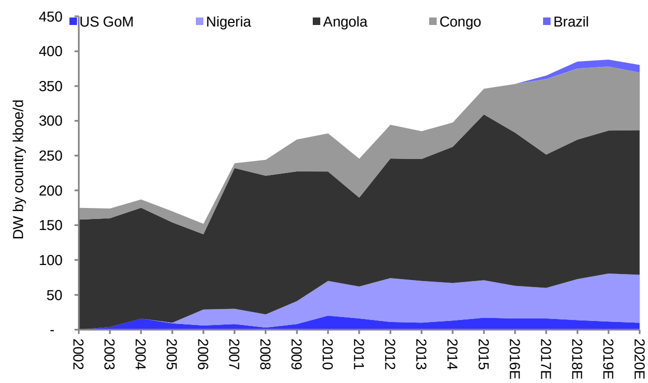
Source: Deutsche Bank, Wood Mackenzie

Total

A West African bias argues that terms or price will need to change

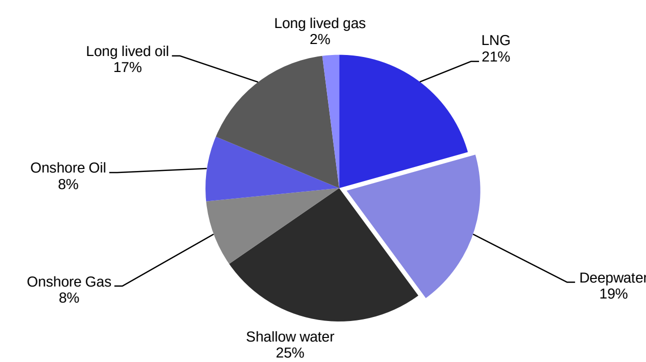
As with its super-major peers, the DW is absolutely key to Total's production profile. The difference in large part, however, is that today Total's key areas of success and dominance have been on the West African Coastline. With material projects under development in Angola (230kb/d Kaombo by 2018 30% total), Egina in Nigeria (200kb/d by 2018, 24%) and the Congo (140kb/d Moho, 53.5%) the deepwater is expected to continue to play an important role in the company's target of 5% CAGR out through 2020, production rising to c350kboe/d. Further out subsequent opportunities in the US GoM (North Platte 40%) and significantly Brazil (Libra 20%), production from which we believe will move towards 200kb/d net to Total by 2030 should allow for continued modest growth with the potential for augmentation from the development of a number of marginal fields in Angola (Zinia 2, Acacia), the change in fiscal terms on which are stated to have significantly improved project economics.

Figure 130: Total's deepwater growth and geographic profile shows that West Africa has been dominant



Source: Deutsche Bank, excludes underdevelopment and recent start-ups, reserves are computed on a net basis and exclude in-fill drilling opportunities

Figure 131: Total: a balanced portfolio in which the DW accounts for c20% of 2020E production



Source: Deutsche Bank

Figure 132: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Block 32 Central NE	Angola	364	30%	100%		Not competitive (several small fields over large area)					
Bolia-Chota	Nigeria	446	7%	76%	2030	$56.80	$73.90	$0.19	$0.72	11%	14%
Jagus East	Brunei Darussalam	50	87%	100%	2022	$58.36	$70.49				15%
Julong East	Brunei Darussalam	150	87%	100%	2023	$62.72	$79.24				12%
Libra	Brazil	5104	20%	100%	2021	$46.34	$58.23	$1.65	$2.50	16%	18%
North Platte (GB 959)	United States	475	40%	92%	2021	$45.74	$53.75	$2.76	$4.64	19%	24%
Tahiti Vertical Expansion*	United States	100	17%	92%	2022	$19.39	$22.51	$13.09	$16.28	74%	87%

Source: Deutsche Bank, blue-lighted metrics represent Wood Mackenzie estimates

Figure 133: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
CA1, Baram Delta	CA1 Total well	Brunei Darussalam	DW	10/1/2016	Total	Total* (54%), BHP Billiton (22.50%), HES (13.50%), Murphy Oil (5%), Petronas Carigali (5%)	--
Area 14, Punta Del Este	Raya-1	Uruguay	UDW	3/30/2016	Total	Total* (50%), XOM (35%), Statoil (15%)	--
Block 11B/12B, Outeniqua	Block 11B/12B-1	South Africa	UDW	7/1/2017	Total	Total* (50%), Canadian Natural Resources (50%)	--
SC56, Sandakan	Halcon-1	Philippines	UDW	2/15/2017	Total	Total* (75%), Mitra Energy Limited (25%)	--
Telen, Kutei Basin	Total Telen well	Indonesia	DW	10/1/2017	Total	Total* (100%)	--
North Platte (GB 959)	North Platte-5	US GoM	DW	10/1/2016	CIE	CIE* (60%), Total (40%)	CIE will commence drilling in North Platte Number 4 appraisal well in 3Q16. North Platte Number 4 is designed to further delineate the North Platte Inboard Lower Tertiary reservoir. Rock and the reservoir properties compare favorably to properties seen in the Miocene reservoirs in the Gulf.

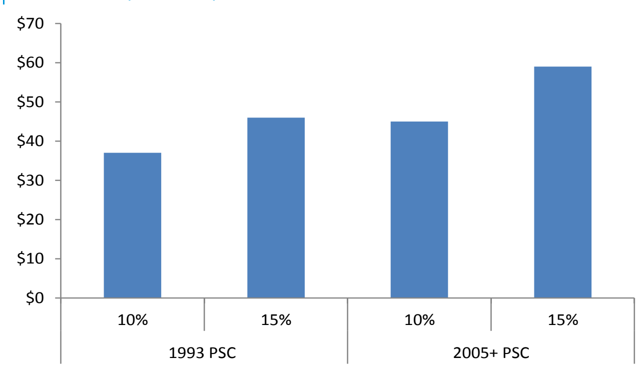
Source: Deutsche Bank, Wood Mackenzie

Exxon Mobil

Beyond Liza, a Deepwater-Portfolio Leveraged Primarily to Nigeria Is Likely to Struggle to Attract Capital Away from Emerging LNG Opportunities

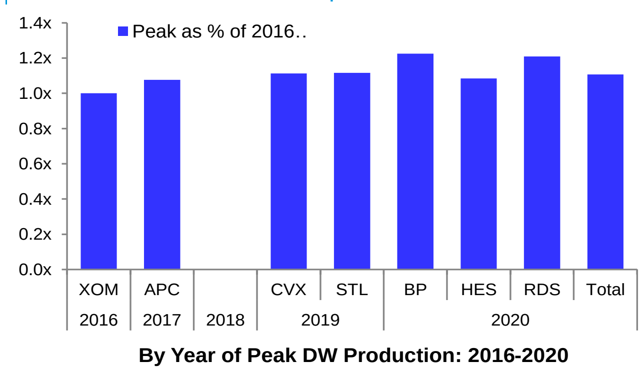
While XOM's Liza discovery seemed to bring some jolt of excitement back to exploration, whose forward portfolio has been noticeably underweight oily, deepwater assets. With Liza clearly world-class, and significant running room in further exploration on the Stabroek License, Guyana is set to feature prominently in future capital allocation. Outside of Guyana, however, the Big Unit's pre-FID deepwater backlog remains mostly levered to an increasingly uncertain resource base in Nigeria. Despite several large-scale, oil-rich high-quality prospects (Bonga Southwest, Bonga North, Bosi, etc), ongoing challenges continue to threaten the development time-line for several of XOM's core discoveries. These challenges involve a re-contracting of fiscal terms for the OML 118 blocks (2025 expiry), high local content requirements (~70% post 2010 lease awards), gas commercialization (Uge) and broader geopolitical concerns.

Figure 134: Bonga SW Break-Even Economics under 1993 PSC (current) and 2005+ Terms



Source: Deutsche Bank, Wood Mackenzie

Figure 135: With a Liza uplift not expected pre-2021, XOM DW volumes are anticipated to decline thru 2020



Source: Deutsche Bank, Wood Mackenzie

Figure 136: Pre-FID List of Major Oil Development Projects

Field	Country	Reserves	WI	% Oil	Start-Up	Break-Even Oil Price		NPV-10 ($/boe)		IRR	
						10%	15%	$60	$70	$60	$70
Block 2	Tanzania	1761	35%	0%	1/1/2027						11%
Block 32 Central NE	Angola	364	15%	100%		Not competitive (several small fields over large area)					
Bonga North	Nigeria	620	20%	91%	6/1/2027	$41.29	$53.64	$1.41	$2.20	18%	22%
Bonga Southwest	Nigeria	901	16%	88%	7/1/2023	$36.81	$47.66	$2.42	$3.47	21%	25%
Bosi	Nigeria	500	56%	55%	6/1/2027	$55.09	$69.23	$0.33	$0.95	12%	15%
Bolia-Chota	Nigeria	446	12%	76%	1/1/2030	$51.27	$66.57	$0.47	$1.04	13%	16%
Uge	Nigeria	171	21%	63%	1/1/2025	$64.03	$74.79	-$0.66	$0.97	8%	13%
Liza	Guyana	1100	45%	100%	1/1/2021	$42.00	$53.00	$3.12	$4.73	18%	21%

Source: Deutsche Bank, Wood Mackenzie

Figure 137: Exploration Calendar

Prospect	Well	Region	Shore Status	Expected Spud Date	Operator	Partner Names	Notes
Liza, Stabroek Block	Liza-3	Offshore Guyana	UDW	9/1/2016	XOM	ExxonMobil* (45%), Hess Corporation (30%), Nexen (25%)	Liza-3 well spud in September 2016. Following the Skipjack well, the operator intends to drill a third well at Liza to further appraise the discovery. Four wells to further explore Liza and the Stabroek
CA1, Baram Delta	Ranger-1	Brunei Darussalam	UDW	1/1/2017	XOM	XOM* (45%), Hess Corporation (30%), Nexen (25%)	--
LB- 13, Liberia Basin	Mesurado-1	Liberia	UDW	1/1/2017	XOM	XOM* (83%), Canadian Overseas Petroleum (17%)	--

Source: Deutsche Bank, Wood Mackenzie

Appendix

Figure 138: Exploration Calendar

Well	Prospect	Region	Operator	Partner Names	Spud Date	Shore Status	Status	Type
--	Block 58	Suriname	APA	APA* (100%)	--	Ultra-deepwater	--	E
--	Block 53	Suriname	APA	APA* (75%), CEPSA (25%)	1Q17	Ultra-deepwater	--	E
Warrior-1	Green Canyon	US GoM	APC	APC* (55%), Ecopetrol (15%), JX Nippon Oil & Energy Corp (15%), Mitsubishi Corporation (15%)	8/1/2016	Deepwater	Proposed Location	E
Shendandoah-6	Shenandoah	US GoM	APC	APC* (30%), COP (30%), CIE (20%), MRO (10%), Venari Resources (10%)	2H16	Ultra-deepwater	--	A
Purple Angel-1	Purple Angle	Colombia	APC	APC* (100%)	10/1/2016	Ultra-deepwater	Proposed Location	E
Paon-3AR ST	Block CI-103	Cote d`Ivoire	APC	APC* (65%), Mitsubishi Corporation (20%), PETROCI (15%)	4/17/2016	Ultra-deepwater	Suspended	A
Rossignol -1	Block CI-528	Cote d`Ivoire	APC	APC* (90%), PETROCI (10%)	8/1/2016	Ultra-deepwater	Proposed Location	E
Pelican-1	Block CI-528	Cote d`Ivoire	APC	APC* (90%), PETROCI (10%)	10/1/2016	Ultra-deepwater	Proposed Location	E
MC 383 #3	Kepler (MC 383)	Na Kika, East Gulf Coast	BP	BP* (50%), Shell (50%)	9/1/2015	Deepwater		A
BEL-1 (Bellatrix)	Sangomar Deep	Senegal - Bove	Cairn Energy	Cairn Energy* (40%), COP (35%), FAR (15%), Petrosen (10%)	3/15/2016	Deepwater	Unknown Status	E
North Platte-5	North Platte (GB 959)	US GoM	CIE	CIE* (60%), Total (40%)	10/1/2016	Deepwater	Proposed Location	A
Panyu 16-5-1	Pearl River Mouth	China	CNOOC Ltd	CNOOC Ltd* (100%)	4/16/2016	Deepwater	Drilling	E
Gator Lake-1	GC/719, West Gulf Coast	US GoM	CVX	CVX* (75%), Venari Resources (25%)	12/1/2016	Deepwater	Proposed Location	E
GB 998 #1 (G31688)	GB/998, West Gulf Coast	US GoM	CVX	CVX* (37.50%), Shell (37.50%), COP (25%)	6/10/2016	Deepwater	Drilling	E
Guadalupe-3	KC/10, West Gulf Coast	US GoM	CVX	CVX* (42.50%), BP (42.50%), Venari Resources (15%)	8/1/2016	Deepwater	Proposed Location	A
Zohr-Deep-1	Zohr, Nile Delta	Egypt	Eni	Eni* (100%)	10/1/2016	Deepwater	Proposed Location	E
Vandumbu-2	Block 15/06 - Vamdunbu, Lower Congo Basin	Angola	Eni	Eni* (35%), Sonangol P&P (35%), Sonangol Sinopec Int (25%), Falcon Oil Holding (5%)	11/1/2016	Deepwater	Proposed Location	A
Ohanga-1	Block 35 - Kwanza	Angola	Eni	Eni* (30%), Sonangol P&P (45%), Repsol (25%)	11/1/2016	Ultra-deepwater	Proposed Location	E
Kekra-1	Offshore Indus G (2265-1)	Pakistan	Eni	Eni* (25%), OGDC (25%), Pakistan Petroleum (25%), United Energy (25%)	12/1/2016	Ultra-deepwater	Proposed Location	E
Ochigufu-3	Block 15/06, Lower Congo	Angola	Eni	Eni* (35%), Sonangol P&P (35%), Sonangol Sinopec Int (25%), Falcon Oil Holding (5%)	9/1/2016	Deepwater	Proposed Location	A
Liza	Liza, Stabroek Block	Offshore Guyana	XOM	XOM* (45%), HES (30%), Nexen (25%)	--	Ultra-deepwater	--	--
Liza-3	Liza, Stabroek Block	Offshore Guyana	XOM	XOM* (45%), HES (30%), Nexen (25%)	9/1/2016	Ultra-deepwater	--	E
CA1 Total well	CA1, Baram Delta	Brunei Darussalam	Total	Total* (54%), BHP Billiton (22.50%), HES (13.50%), Murphy Oil (5%), Petronas Carigali (5%)	10/1/2016	Deepwater	Proposed Location	E
Ranger-1	CA1, Baram Delta	Brunei Darussalam	XOM	XOM* (45%), HES (30%), Nexen (25%)	1/1/2017	Ultra-deepwater	Proposed Location	E
--	Offshore Nova Scotia	Canada Offshore	BP	BP* (50%), HES (40%), Woodside Petroleum (20%)	2Q18	Shelf - UDW	--	--
--	Tubular Bells (MC 725)	US GoM	HES	HES (57.14%), CVX (42.86%),	6/15/2016	Deepwater	--	--
--	Block 42	Suriname	KOS	KOS* (33.34%), CVX (33.33%), HES (33.33%)	3Q16	Shelf - UDW	--	--
--	Blocks 6, 11 & 12 - Rio Munni Basin	Offshore Sao Tome	KOS (Blocks 11 & 12), Galp Energia (Block 6)	Block 6 - Galp Energia* (45%), KOS (45%), Gov. of Sao Tomé/Principe (10%); Block 11 - KOS* (85%), Gov of Sao Tomé/Principe (15%); Block 12 - KOS* (65%), Equator Exploration (22.50%), Gov of Sao Tomé/Principe (12.50%)	1Q17	Shelf - UDW	--	--
South Senegal -1	St Louis Offshore Profond, Senegal - Bove	Senegal	KOS	KOS* (60%), Timis Corp (30%), Petrosen (10%)	1/1/2017	Deepwater	Proposed Location	E
South Senegal -2	St Louis Offshore Profond, Senegal - Bove	Senegal	KOS	KOS* (60%), Timis Corp (30%), Petrosen (10%)	3/1/2017	Deepwater	Proposed Location	E
WR 51 #4 (G31938)	WR/51, West Gulf Coast	US GoM	APC	APC* (30%), COP (30%), CIE (20%), MRO (10%), Venari Resources (10%)	3/14/2016	Ultra-deepwater	Drilling	A
2613A-1	2613A, Southwest African Coastal	Namibia	MUR	Murphy Oil* (40%), OMV (25%), Cowan Petroleo e Gas (20%), Namcor (15%)	1/1/2017	Deepwater	Proposed Location	E
Haleakala-1	MC/977, East Gulf Coast	US GoM	APC	APC* (33.34%), Ecopetrol (25%), Murphy Oil (25%), W & T Offshore (16.66%)	6/1/2017	Deepwater	Proposed Location	E
Opal-1	DC/853, East Gulf Coast	US GoM	APC	APC* (50%), Murphy Oil (50%)	1/1/2017	Ultra-deepwater	Proposed Location	E

Source: Deutsche Bank, Wood Mackenzie

Figure 139: Exploration Calendar (Continued)

Well	Prospect	Region	Operator	Partner Names	Spud Date	Shore Status	Status	Type
Flamingo-B	Neptun Deep	Black Sea, Romania	XOM	XOM* (50%), OMV Petrom (50%)	8/1/2016	Deepwater	Proposed Location	E
Lopatar-2	Neptun Deep	Black Sea, Romania	XOM	XOM* (50%), OMV Petrom (50%)	8/1/2016	Ultra-deepwater	Proposed Location	E
PEP 54863 Shell well-1	PEP 54863, Great South	New Zealand	RDS	Shell* (59%), OMV (26%), Mitsui & Co (15%)	4/1/2017	Deepwater	Proposed Location	E
3BRSA-1339A-RJS	Libra, Santos Basin	Brazil	Petrobras	Petrobras* (40%), Shell (20%), Total (20%), CNOOC Ltd (10%), CNPC (10%)	2/21/2016	Ultra-deepwater	Drilling	A
3BRSA-1342A-RJS	Libra, Santos Basin	Brazil	Petrobras	Petrobras* (40%), Shell (20%), Total (20%), CNOOC Ltd (10%), CNPC (10%)	4/24/2016	Ultra-deepwater	Drilling	A
Cronus-1	AC/P 52. Browse Basin	Australia	RDS	Shell* (50%), Sasol (30%), Finder Exploration (20%)	10/1/2016	Deepwater	Proposed Location	E
Ipanema-1	WR/376, West Gulf Coast	US GoM	RDS	Shell* (100%)	10/1/2016	Ultra-deepwater	Proposed Location	E
Monterey Jack-1	EL 2424, Scotian Shelf	Canada	RDS	Shell* (50%), COP (30%), Suncor Energy (20%)	11/1/2016	Ultra-deepwater	Proposed Location	E
OPL 245-1	OPL 245, Niger Delta	Nigeria	Eni	Eni* (50%), Shell (50%)	1/1/2017	Ultra-deepwater	Proposed Location	E
3REPF-0017-RJS	C-M-539, Campos Basin	Brazil	Repsol Sinopec Brasil	Repsol Sinopec Brasil* (35%), Statoil (35%), Petrobras (30%)	1/8/2016	Ultra-deepwater	Drilling	A
Fitzroya A-12Z	EL 1126, Jeanne d`Arc	Canada	Statoil	Statoil* (50%), CVX (40%), BG (10%)	2/11/2016	Deepwater	Drilling	E
Raya-1	Area 14, Punta Del Este	Uruguay	Total	Total* (50%), XOM (35%), Statoil (15%)	3/30/2016	Ultra-deepwater	P & A	E
Stromlo-1	EPP-37, Great Australian Bight	Australia	BP	BP* (70%), Statoil (30%)	12/31/2016	Ultra-deepwater	Proposed Location	E
A-6 Woodside Petroleum well-1	Block A6, Bengal Delta Sub-basin- Bengal	Myanmar	Woodside Petroleum	Woodside Petroleum* (40%), Myanmar Petroleum Resources* (20%), Total (40%)	1/1/2017	Ultra-deepwater	Proposed Location	E
A-6 Woodside Petroleum well-2	Block A6, Bengal Delta Sub-basin- Bengal	Myanmar	Woodside Petroleum	Woodside Petroleum* (40%), Myanmar Petroleum Resources* (20%), Total (40%)	4/1/2017	Ultra-deepwater	Proposed Location	E
Block 11B/12B-1	Block 11B/12B, Outeniqua	South Africa	Total	Total* (50%), Canadian Natural Resources (50%)	7/1/2017	Ultra-deepwater	Proposed Location	E
Halcon-1	SC56, Sandakan	Philippines	Total	Total* (75%), Mitra Energy Limited (25%)	2/15/2017	Ultra-deepwater	Proposed Location	E
KC 129 #1ST2 (G30924)	KC/129, West Gulf Coast	US GoM	CIE	CIE* (46.87%), Total (27.46%), Samson Energy (25.67%)	6/19/2016	Ultra-deepwater	Drilling	E
Total Telen well	Telen, Kutei Basin	Indonesia	Total	Total* (100%)	10/1/2017	Deepwater	Proposed Location	E
Skipjack	Stabroek Block	Offshore Guyana	XOM	XOM* (45%), HES (30%), Nexen (25%)	7/17/2016	Shelf	Dry Hole	E
Mesurado-1	LB- 13, Liberia Basin	Liberia	XOM	XOM* (83%), Canadian Overseas Petroleum (17%)	1/1/2017	Ultra-deepwater	Proposed Location	E
Tulip-1	Block Z, Niger Delta	Equatorial Guinea	RoyalGate Energy	RoyalGate Energy* (80%), GEPetrol (20%)	10/1/2016	Deepwater	Proposed Location	E
Ohanga-1	Block 35 - Kwanza	Angola	Eni	Eni* (30%), Sonangol P&P (45%), Repsol (25%)	11/1/2016	Ultra-deepwater	Proposed Location	E
--	Block-1	Rovuma Basin, Tanzania	RDS	Shell (60%), Ophir Energy (20%), Pavillion Energy (20%)	2H16	Shelf - UDW	Proposed Location	--
--	Block-4	Tanzanian Coastal	RDS	Shell (60%), Ophir Energy (20%), Pavillion Energy (20%)	2H16	Deepwater	Proposed Location	--

Source: Deutsche Bank, Wood Mackenzie

Appendix 1

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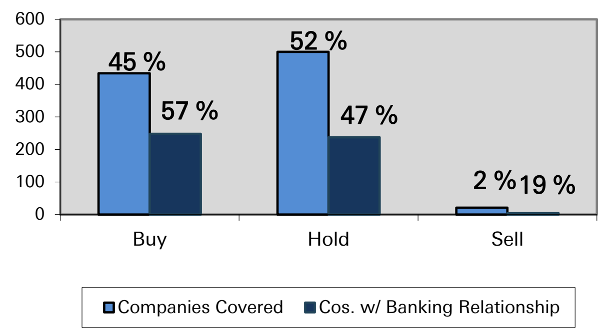

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