Deutsche Bank
Markets Research

North America
Canada
United States
Industrials
Oil Services & Equipment

Industry
Initiation of coverage

Date
9 October 2017

Initiation of Coverage

Not Business as Usual

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We are initiating coverage of the Oilfield Service and Equipment sector, and in a break from our longstanding negative view, we have no Sell rated stocks and have nine Buy recommendations. Our top picks are PTEN, HAL and CJ . We are also initiating with Buy recommendations on SLB, CLB, RIG, WFT, SPN and SND. We are encouraged by the judicious selloff in the stocks year-to-date, and by what also appears to be a market that is acknowledging the obsolescence of the old cyclical playbook. Earnings revisions that had initially taken an impractical leap higher in 2H16 have been revised down considerably, providing a significantly better setup for the stocks.

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Top picks	
C&J Energy Services (CJ.N),USD29.66	Buy
Patterson-UTI (PTEN.OQ),USD20.76	Buy
Halliburton (HAL.N),USD44.93	Buy

Source: Deutsche Bank

Initiation of coverage
We are initiating coverage of the Oilfield Service and Equipment sector, and in a break from our longstanding negative view, we have no Sell rated stocks and have nine Buy and 15 Hold recommendations. Our top picks are Patterson-UTI (PTEN), Halliburton (HAL) and C&J Energy Services (CJ) . We are also initiating with Buy recommendations on Schlumberger (SLB), Core Laboratories (CLB), Transocean (RIG), Weatherford (WFT), Superior Energy Services (SPN) and Smart Sand (SND). We are encouraged by the judicious selloff in the stocks year-to-date, and by what also appears to be a market that is acknowledging the obsolescence of the old cyclical playbook. Earnings revisions that had initially taken an impractical leap higher in 2H16 have been revised down considerably, providing a significantly better setup for the stocks.

Not business as usual for the oilfield services industry
This is an industry that is still in transition, and these are companies that still need to navigate this transition. The commercial development of tight oil reserves in the US was disruptive and it derailed the normalization of the cycle. The business models that worked last cycle will not necessarily work again this cycle. We believe in the long term, the oilfield service franchises that will be the winners will be those that evolve with innovative business models, and those that acquire or invest in niche technology leaders.

Pressure pumping demand poised to recover to 2014 highs
The biggest common denominator among our top picks is exposure to pressure pumping. As US producers tailor their drilling programs to focus increasingly on their core acreage and best wells, there will be a disproportionate mix of leading edge, longer lateral wells with tighter stage spacing and higher sand loadings. This will drive the average completion intensity per well even higher, which should restore the demand for horsepower to the 2014 highs despite a lower rig count.

Valuation and risks
See our Industry valuation and risks within the Executive Summary section of this report, and company specific valuation and risks within individual company pages.

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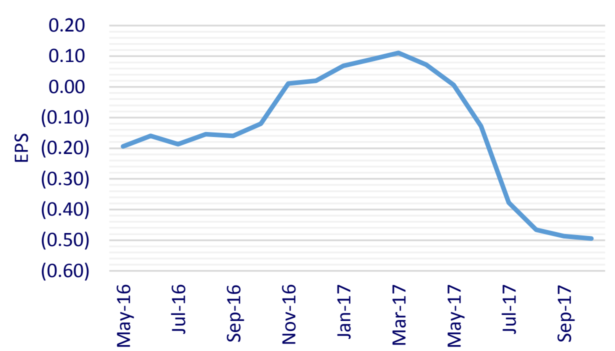
Executive summary

We are initiating coverage on 24 oilfield service and equipment stocks, and in a break from our longstanding negative view, we have no Sell rated stocks and have nine Buy recommendations. Our top picks are PTEN, HAL, and CJ. We are also initiating with Buy recommendations on SLB, CLB, RIG, WFT, SPN and SND. We are encouraged by the judicious selloff in the stocks year-to-date, and by what also appears to be a market that is acknowledging the obsolescence of the old cyclical playbook. Earnings revisions that had initially taken an impractical leap higher in 2H16 have been revised down considerably, providing a significantly better setup for the stocks.

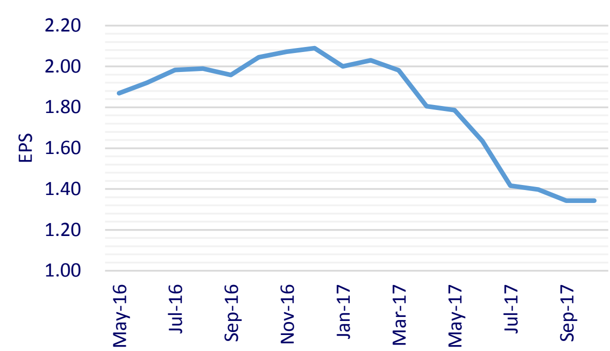
Furthermore, our unchanged US oil supply growth estimate for 2017 has gone from being unrealistically high to now being in-line with market expectations. For 2018, we actually find our growth estimate of 0.7 mmb/d to be below the consensus of 0.9-1.0 mmb/d. Thus for the first time in a long time, we believe the setup for the stocks is less vulnerable to misinterpretations of the macro and negative earnings revisions. Now we do expect oil prices to be confined to a range of $45-55 per barrel (WTI) through 2018. As such, we do not expect the stocks to reach escape velocity. But we do see select opportunities for upside irrespective of our flattish spending outlook for the US, and continued challenges in international markets.

Figure 1: Land driller EPS revisions (2018 EPS)



Source: Factset (includes HP, NBR, PDS)

Figure 2: Integrated services EPS revisions (2018 EPS)



Source: Factset (includes SLB, HAL, BHI, WFT)

Pressure pumping demand is poised to recover to the 2014 highs

The biggest common denominator among our top picks is exposure to pressure pumping. As US producers tailor their drilling programs to focus increasingly on their core acreage and best wells, there will be a disproportionate mix of leading edge, longer lateral wells with tighter stage spacing and higher sand loadings in our view. This will drive the average completion intensity per well even higher, which should restore the demand for hydraulic horsepower (hhp) to the 2014 highs despite a lower rig count. The key beneficiaries are Buy rated CJ, HAL, PTEN and Hold rated RPC Inc (RES). Buy rated SND is also a beneficiary as sand demand reaches new all-time highs, but expect supply additions to mitigate the degree of scarcity value experienced last year. CLB also benefits as frac equipment is reactivated, debottlenecking the completions market, and enabling producers to drawdown the increased inventory of drilled but uncompleted wells.

Figure 3: Valuation table

Sub-sector (company)	Symbol	Rating	5-Oct price	12-mo target	Mkt cap ($m)	EPS (DBe) '17DB	'18DB	'19DB	EPS (consensus) '18	'19	PE '18DB	'19DB	EBITDA (DBe) '18DB	'19DB	EBITDA (consensus) '18	'19	EV/EBITDA '18DB	'19DB	Debt turns	Price/ book
INTEGRATED SERVICES																				
Schlumberger	SLB	Buy	68.87	78	94,499	1.47	2.38	3.33	#N/A	#N/A	28.9	20.7	8,225	9,740	8,568	10,370	13.1	11.0	2.3	2.4
Halliburton	HAL	Buy	45.09	54	38,603	1.14	2.22	2.99	2.17	2.96	20.3	15.1	4,810	5,629	4,761	5,774	9.9	8.5	2.3	4.3
Baker Hughes	BHGE	Hold	36.48	35	15,674	0.12	1.31	1.75	1.27	1.97	27.9	20.8	3,083	3,702	3,787	4,873	4.8	4.0	1.0	1.3
Weatherford	WFT	Buy	4.27	6	4,140	(1.01)	(0.28)	0.02	(0.45)	(0.01)	nm	254.0	905	1,040	904	1,296	12.5	10.9	8.5	2.8
SMID SERVICES																				
Core Laboratories	CLB	Buy	95.99	109	4,146	1.90	2.92	3.67	2.73	3.39	32.9	26.1	188	228	180	218	23.4	19.3	1.2	28.1
Superior Energy Services	SPN	Buy	10.42	15	1,532	(1.53)	(0.85)	(0.25)	(0.69)	(0.20)	nm	nm	359	nm	392	467	7.4	nm	3.6	1.3
Frank's International	FI	Hold	7.67	7	1,659	(0.45)	(0.26)	(0.05)	(0.25)	(0.03)	nm	nm	52	100	57	113	26.9	13.8	0.0	1.3
Basic Energy Services	BAS	Hold	19.77	22	488	(2.05)	(0.35)	0.75	(0.25)	0.98	nm	nm	134	nm	143	187	5.3	nm	1.9	1.3
C&J Energy Services	CJ	Buy	29.56	39	1,826	0.13	2.16	3.68	2.02	3.06	13.7	8.0	351	481	331	462	4.4	3.2	-	1.6
RPC, Inc.	RES	Hold	23.98	25	5,070	0.83	1.42	1.50	1.38	1.49	16.9	16.0	628	660	632	692	7.8	7.4	-	6.0
SAND SUPPLIERS																				
Smart Sand	SND	Buy	7.01	9	271	0.33	0.86	0.97	0.79	0.98	8.1	7.2	68	77	64	72	3.1	2.7	0.0	1.6
LAND DRILLERS																				
Helmerich & Payne	HP	Hold	52.17	45	5,584	(1.34)	(0.79)	(0.12)	(0.66)	(0.21)	nm	nm	450	551	461	539	12.1	9.9	1.1	1.3
Nabors Industries	NBR	Hold	7.99	9	2,161	(1.47)	(0.51)	0.30	(0.61)	(0.04)	nm	27.1	830	1,049	822	1,023	6.8	5.4	4.5	0.7
Patterson-UTI Energy	PTEN	Buy	21.30	25	4,428	(0.91)	(0.17)	0.38	(0.23)	0.26	nm	55.7	787	969	771	923	6.2	5.0	0.9	1.2
Precision Drilling	PD-CA	Hold	3.57	4	1,018	(0.35)	(0.15)	0.15	(0.31)	(0.04)	nm	24.4	392	522	381	493	7.1	5.3	4.7	0.5
OFFSHORE DRILLERS																				
Diamond Offshore	DO	Hold	14.88	15	2,020	0.95	0.16	(0.32)	0.16	(0.04)	93.7	nm	457	356	464	421	8.4	10.8	4.3	0.5
Ensco Plc	ESV	Hold	5.83	6	1,713	(0.57)	(1.89)	(1.13)	(0.73)	(0.75)	nm	nm	481	312	460	478	9.6	14.7	9.9	0.2
Noble Corporation	NE	Hold	4.50	4	1,017	(1.29)	(1.39)	(1.37)	(1.39)	(1.35)	nm	nm	409	335	412	408	12.6	15.4	9.9	0.2
Rowan Companies	RDC	Hold	13.02	15	1,639	(0.61)	(1.93)	(2.23)	(2.37)	(2.52)	nm	nm	231	150	208	156	13.0	20.1	10.9	0.3
Transocean	RIG	Buy	10.54	13	4,004	0.03	(0.94)	(1.58)	(0.94)	(1.23)	nm	nm	888	629	909	821	9.5	13.4	8.3	0.3
CAPITAL EQUIPMENT																				
National Oilwell Varco	NOV	Hold	36.03	39	13,356	(0.40)	0.55	1.32	0.43	1.29	65.6	27.3	1,007	1,313	1,000	1,423	14.9	11.4	3.2	1.0
Oil States International	OIS	Hold	25.55	26	1,297	(0.99)	(0.23)	0.29	(0.20)	0.44	nm	88.9	106	146	100	144	11.8	8.6	0.5	1.1
Oceaneering International	OII	Hold	25.47	28	2,480	0.03	0.14	0.52	0.09	0.52	184.1	49.1	239	285	252	313	11.7	9.8	3.3	1.7
Forum Energy Technologies	FET	Hold	15.50	17	1,621	(0.27)	0.23	0.66	0.21	0.61	67.3	23.6	114	176	124	186	14.2	9.2	3.5	1.4

Source: Deutsche Bank, Factset

Land drillers are looking to reestablish themselves in the value chain

There is a higher cadence of more productive wells being developed in the US that is undermining the earnings power of the land drilling industry. The trend of drilling more with less threatens the marketability of the entire legacy land rig fleet as producers continue to demand technologies that enable improved drilling efficiencies and lower well costs. This has reserved pricing power for the preferred AC-electric and super-spec rigs, but even at above 90% utilization, pricing power for these rigs is struggling to breakout. Unlike the frac market, we do not expect rig counts to be restored to the 2014 highs by year-end 2018. But while this sub-sector was once an alpha short as earnings revision leaped to impractical levels in 2016, revisions have since been sharply negative, leaving the stocks less vulnerable in our view. We initiate with Hold ratings on Helmerich & Payne (HP), Nabors Industries (NBR) and Precision Drilling (PD). PTEN is Buy rated due to its frac exposure.

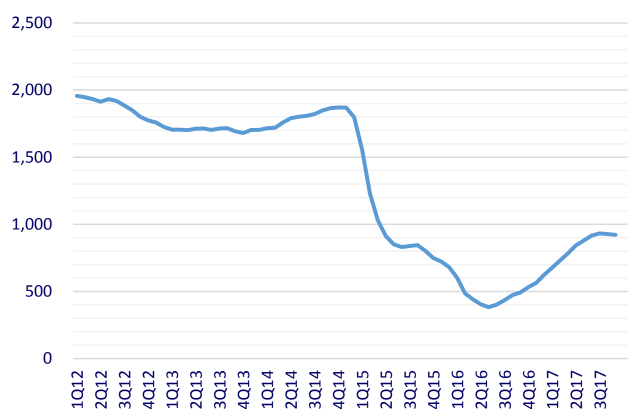
US service inflation will continue at a more modest pace

Inflation expectations got ahead of the market last year, but have since been roped in. If oil prices stay within our $45-55 range, we expect inflation will stay below 10% in 2018 with only pressure pumping stepping higher to about 15%. In a lower oil price environment, moderate oil price inflation is not negative. Restoring volumes at this stage of the cycle and absorbing fixed costs are the principal drivers of margin expansion. If service inflation is allowed to breakout in a low price environment with increasingly louder calls for producers to exercise capital discipline, we fear our flat rig count assumption for 2018 will have increased downside risk.

Rig count outlook domestically and abroad are flattening

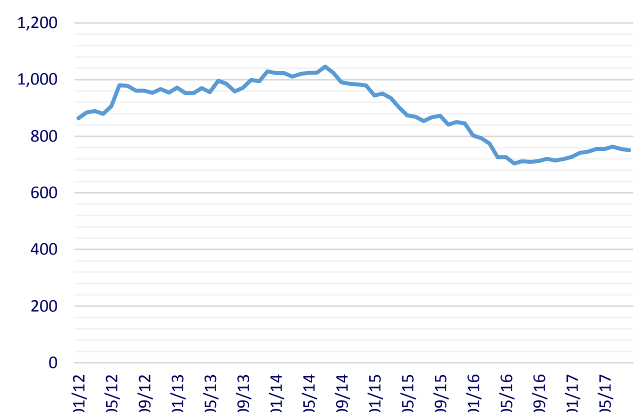
The US experienced a rapid drilling recovery once oil prices inflected, but international markets remained a lot more sluggish. We expect an ebb and flow of US upstream capital expenditures to keep pressure on oil prices and a lid on rig counts both domestically and abroad. The one exception where we see continued resilience is in Saudi Arabia. The standout exposures to Saudi Arabia are Buy rated Schlumberger (SLB), and Hold rated NBR and Rowan Companies (RDC).

Figure 4: US onshore rig count



Source: Baker Hughes, a GE Company

Figure 5: International onshore rig count



Source: Baker Hughes, a GE Company

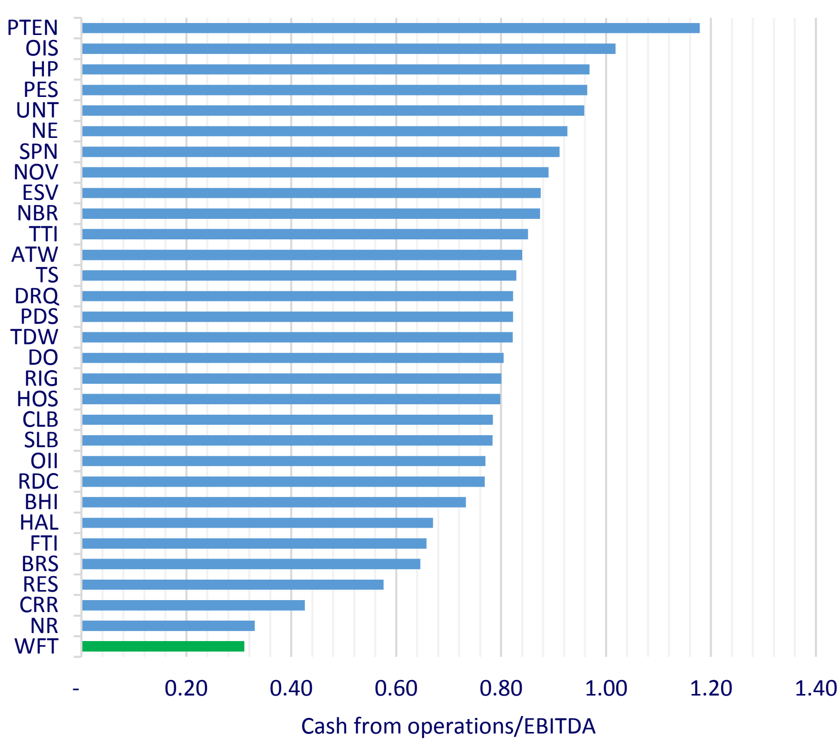
Offshore markets bottoming, limited momentum, but some opportunity

For the offshore drillers, the negative sentiment remains firmly entrenched, but we believe the alpha short is largely gone and the industry is bottoming. The issue is the recovery will lack momentum and earnings are still trending lower each year through 2019. The competitive landscape will likely change significantly as more deals are announced in an effort to reposition fleets. Attrition will likely continue once deals are closed. We initiate with a Hold rating on DO, ESV, NE, and RDC, and Buy rating on RIG. RIG has delivered a strong positive free cash flow track record and has preserved cash, and maintained a leading edge ultra-deepwater fleet with above average marketability. We believe the company is well positioned to make opportunistic acquisitions in an otherwise financially stressed sub-sector.

Weatherford is one of the key idiosyncratic stories

Culture and process. The two things the new CEO needs to change at WFT. Not an easy fix, but if WFT can move up from being dead last on a 10-year average cash conversion comparison (cash from operations/EBITDA) with 30 other oilfield service companies, we believe there is meaningful upside. Weatherford lost about $6 billion in free cash flow over the last ten years while SLB and NOV generated approximately $33 billion and $14 billion respectively. The new leadership has identified several operating and process related levers to pull, a key one being inventory days that are approximately twice as high as SLB and HAL. Unrealistic to expect a similar level of working capital efficiency as these peers, but even meeting half way moves the needle. In the near-term, equity financing remains a key risk as its international land sales remain challenged.

Figure 6: Average 10-year cash conversions (cash from operations/EBITDA)



Source: Factset, Deutsche Bank

Not business as usual for the oilfield services industry

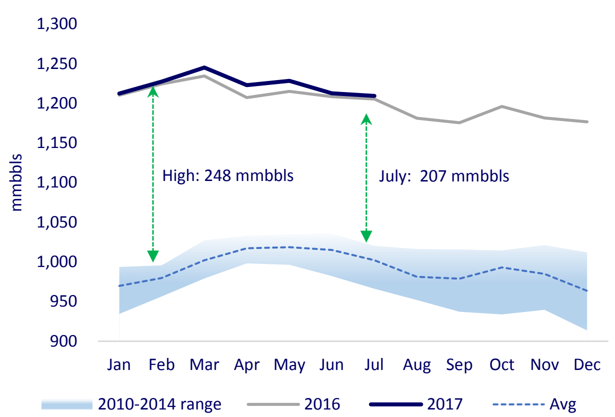
This is an industry that is still in transition, and these are companies that still need to navigate this transition. The commercial development of tight oil reserves in the US was a remarkable achievement, but it was disruptive, and it derailed the normalization of the cycle. The business models that worked last cycle will not necessarily work again this cycle. There is a louder call for capital discipline among producers, which are requiring increasingly more intellectual property, data analytics, Big Data and precision well placement capabilities to lower costs and improve returns. As such, we believe in the long-term, the oilfield service franchises that will be the winners will be those that evolve with innovative business models, and those that acquire or invest in niche technology leaders.

Within this context, we believe the standouts are Buy rated SLB, HAL, PTEN, and CLB , and Hold rated NBR. These companies are evolving to maximize margin and returns in an otherwise challenging market. SLB in particular has been addressing the industry-wide sub-optimal asset turns and tool utilization in an effort to enable above average margins in a market where its peers are fighting for market share. The company is also taking the most radical look at the future of the industry with its efforts in redefining the entire drilling process and industry workflows.

This cycle will not be like the prior two cycles

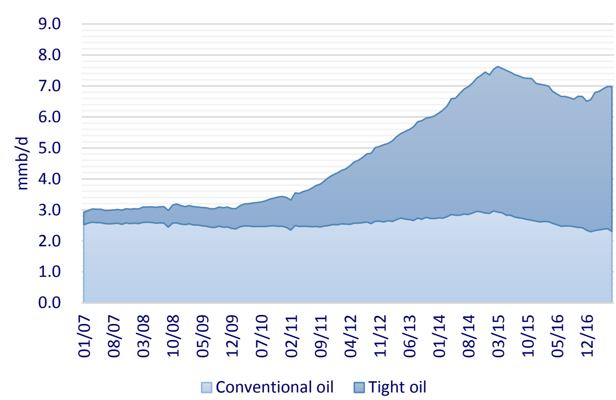
In order for these stocks to sustain a rally, we need to see progress in the rebalancing of the oil markets. While we do believe well productivity will continue to keep some pressure on oil prices, US production expectations got a bit ahead of themselves in our view. But we do not expect the same proliferation of spending as last cycle, but instead a more measured outcome.

Figure 7: Global oil inventories showing some progress



Source: EIA

Figure 8: Higher cadence of more productive wells in US



Source: EIA, Drilling Info

Industry valuation and risks

Our price target methodology is based on either the five-year or ten-year multiple of each company's normalized earnings or EBITDA power. We then look a standard deviation above and below, and calculate the price target from a weighted average. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) pricing tactics getting increasingly more aggressive for market share, and 4) another leg down in deepwater spending globally.

The Ebb and Flow of US Capex Keeps Pressure on Oil Prices

We are still mindful of the headwinds. US oil producers are developing a higher cadence of more productive wells for less capital at lower breakeven prices. They have built 10-20 year drilling inventories with 96% success rates and 3-6 month cash conversions. They have capex budgets that can ebb and flow with oil prices and they are standing ready to deploy capital once oil prices edge up above $50.

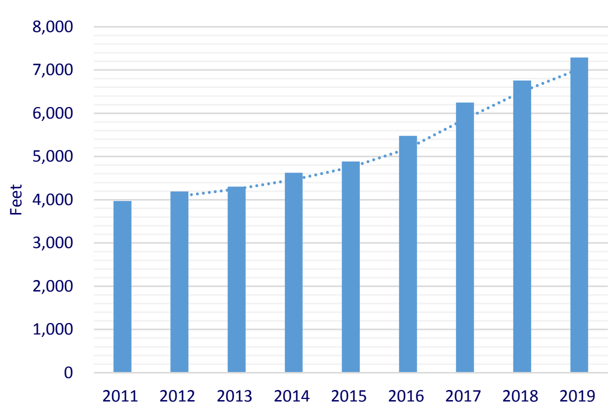
When all is said and done, the US is exerting more influence on global oil markets than it has in over 30 years. US producers collectively are undermining OPEC and the oil rebalancing effort. We believe the ebb and flow of US capex and the rehabilitation of US productivity will confine oil prices to a range of $45 – 55 through 2018. This will restrain service inflation when oil prices are below $50, and it will be an obstacle to restoring earnings power.

The unintended consequences of higher density drilling and completions

The rehabilitation of US well productivity is a direct result of longer laterals, tighter stage spacing, more frac clusters, and higher sand loadings. We expect these trends to continue, and for the next 3+ years, US producers will enhance completion intensities in an effort to increase productivity. We also expect to see increasingly more technology brought into the fold including precision well placement, data analytics, and real-time monitoring, all of which we believe will increase year-over-year estimated ultimate recoveries (EURs) and initial production (IP) rates.

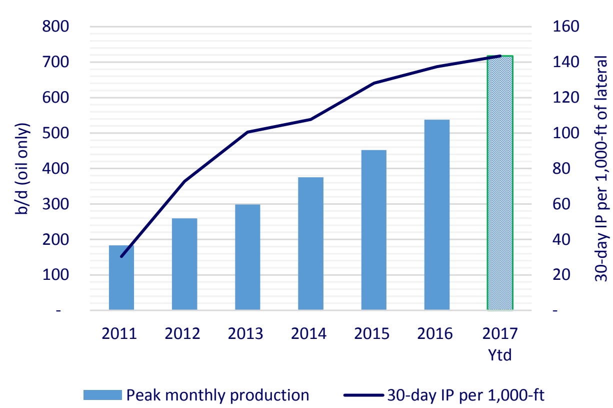
But what merits close attention is the increasing trend toward close proximity drilling. These 10-20 year drilling inventories are populated with a number of infill drilling wells that present some risks including parent child well interference, which could drive actual EURs lower than expected. This is getting a lot of mind share as producers return to existing pads to infill drill. While we have always hesitated to doubt future progress in well productivity, that was during the early innings of tight oil development.

Figure 9: Average Permian horizontal lateral lengths



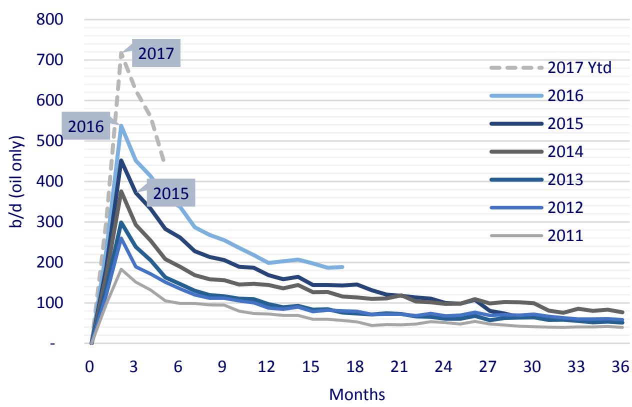
Source: IHS Markit

Figure 10: Average Permian 30-day IPs per 1,000-ft



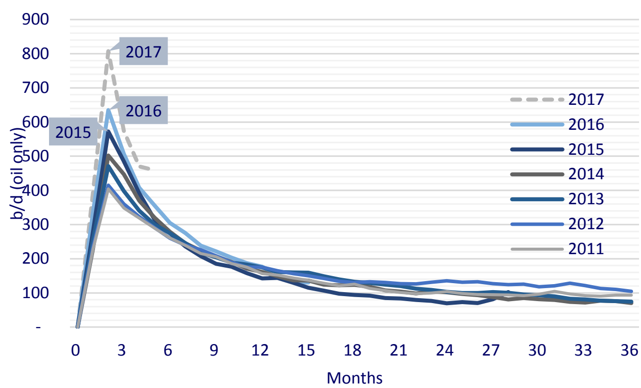
Source: Drilling Info, Deutsche Bank

Figure 11: Permian type curves by vintage



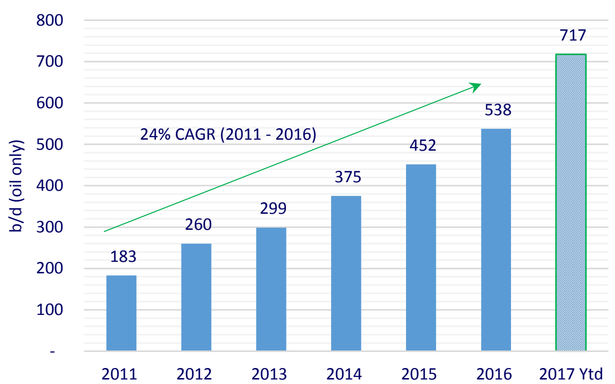
Source: Drilling Info, Deutsche Bank

Figure 12: Eagle Ford type curves by vintage



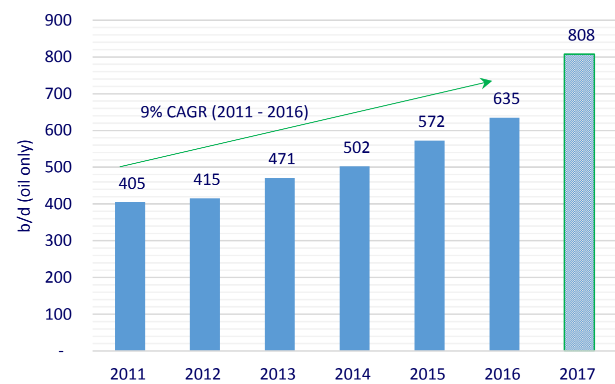
Source: Drilling Info, Deutsche Bank

Figure 13: Permian peak 30-day production averages



Source: Drilling Info, Deutsche Bank

Figure 14: Eagle Ford peak 30-day production averages



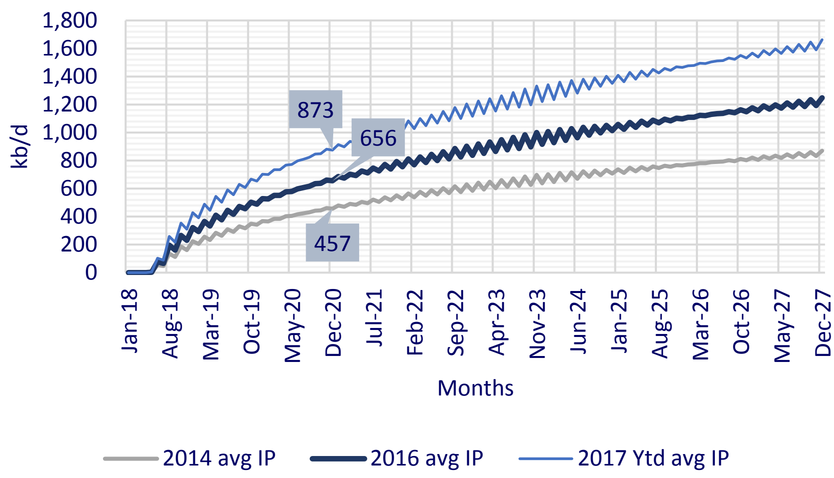
Source: Drilling Info, Deutsche Bank

Developing a higher cadence of more productive wells in the US

The ebb and flow of US capex with oil prices is nothing new, but the development of US tight oil reserves has radically rehabilitated the cause-and-effect relationship between drilling and production. For over a decade, US oil production had remained relatively flat despite oscillations in oil-directed capex. Tight oil has changed that and has encouraged significant investment in optimizing completion designs that enhance reservoir contact and productivity per lateral foot. This has made the US a principal market for producers.

Since 2011, the average initial production (IP) rates and estimated ultimate recoveries (EURs) for wells placed-on-production (POP) in the main tight oil basins have been increasing. The peak 30-day production numbers for the Permian have increased at a CAGR of 24% while the Eagle Ford has increased at a CAGR of 9%. Most of the improvements were a direct result of longer laterals, more frac stages, and more sand. While we expect the positive trend to persist through 2018, we do believe the rate of change will slow due to some interference from technical and economic break points.

Figure 15: The impact of adding 100 rigs has increased significantly



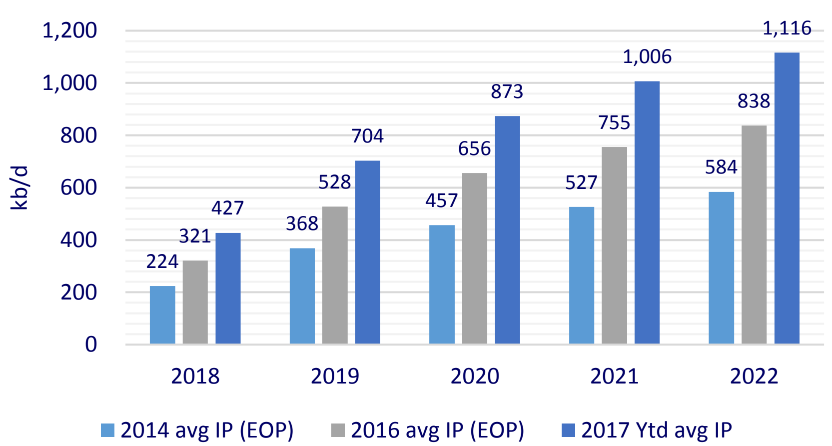
Source: Drilling Info, Deutsche Bank

Tight oil has rehabilitated the influence of the US rig count

A producer working a single rig on a multi-well pad in the Permian can drill a well in 20 days and can have a three-well pad placed on production in 130 days or less. It can spud 18 wells per year with a completed well cost normalized for a 7,500-ft lateral of $5.5 – 6.0 million. Total annual drilling and completion (D&C) expenditures for this single rig would be $100 – 110 million.

Scale this up to a development program with 100 rigs and $10 – 11 billion of annual D&C expenditures, and within 12-months of spudding the first wells, this program can produce 0.4 mmb/d of oil. By the end of year-three, output is upwards of 0.9 mmb/d. This is almost double what the industry was doing in 2014. This is what seduces US producers and brings capital into the US.

Figure 16: Permian year-end flow rate contributions when adding 100 rigs



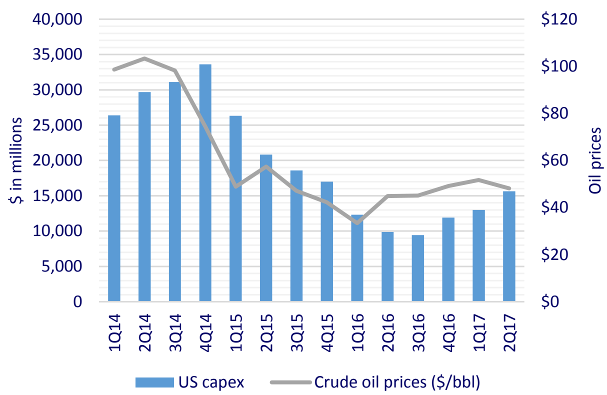
Source: Drilling Info, Deutsche Bank

Capex Recovery is rapidly Reviving US Oil Production

We believe the upstream capex recovery that began in June 2016 has put the US on track to realize 9.5 mmb/d of oil production by year-end 2017. This would be a 1.0 mmb/d revival since the September 2016 lows, of which 0.55 mmb/d has been restored as of June 2017. While the drawdown of drilled but uncompleted wells (DUCs) has contributed about 0.24 mmb/d of the restored oil so far, we expect the 450 oil-directed rigs that have returned to work since June 2016 to contribute about 0.85 mmb/d of oil production by year-end 2017.

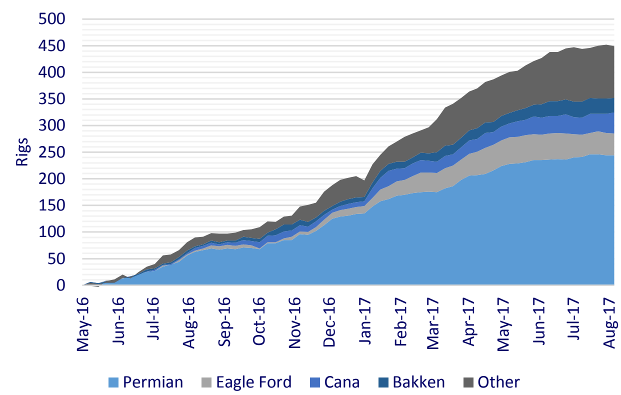
We believe this rapid revival of US production is exerting pressure on global oil prices and is likely to flatten 2018 capex budgets and US rig count growth. We do not expect it will once again drive oil prices down into the $30s.

Figure 17: US upstream capex bottomed in 3Q16 and has risen 65% through 2Q17 with oil prices averaging $47



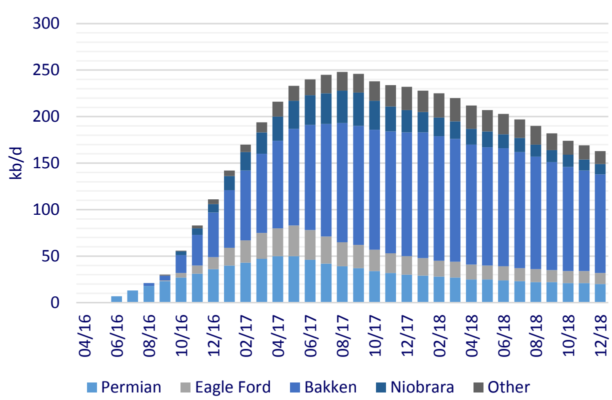
Source: Company reports from the top 30 active US producers

Figure 18: The Permian has absorbed 54% of the land rigs returning to the field since the May 2016 rig inflection



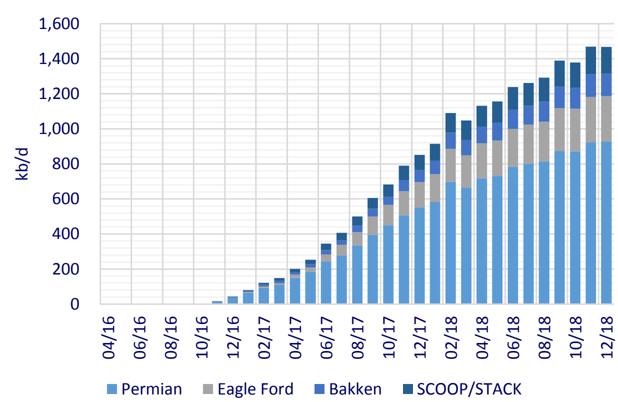
Source: Baker Hughes, a GE Company

Figure 19: DUCs responded quickly and at the peak are contributing about 0.24 mmb/d



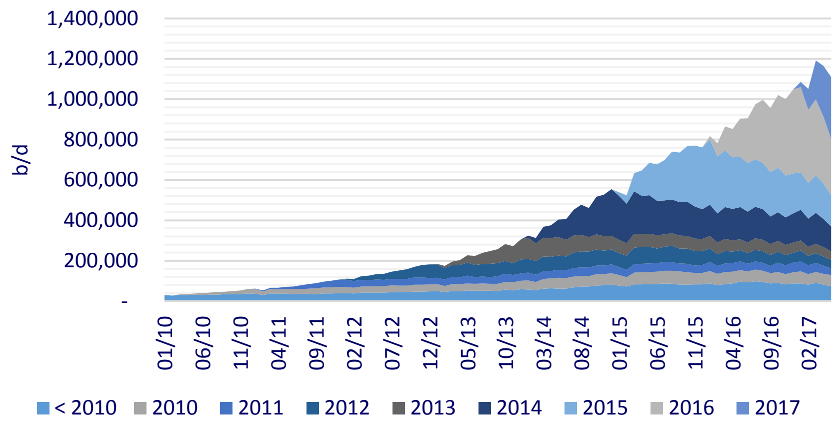
Source: Wood Mackenzie, Drilling Info, Deutsche Bank

Figure 20: Newly drilled wells contributing approximately 0.85 mmb/d by year-end 2017



Source: Wood Mackenzie, Drilling Info, Deutsche Bank

Figure 21: Permian production by well vintage



Source: Drilling Info, Deutsche Bank

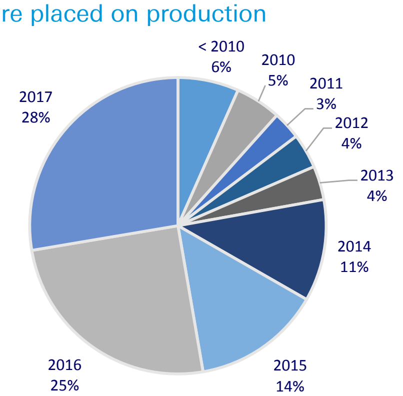
The Permian is the principal driver of activity and oil production growth

The rapid revival of production is happening largely in the Permian. Over 50% of the rigs that have returned to work since the June 2016 inflection have gone to the Permian. We expect these rigs will contribute approximately 0.55 mmb/d of production by year-end 2017.

But even before the inflection in drilling activity, the Permian has experienced significant production growth with over 65% of the total output coming from wells placed on production since 2015. To put that into context, wells placed on production in the Eagle Ford since 2015 are only contributing about 30% of the total output.

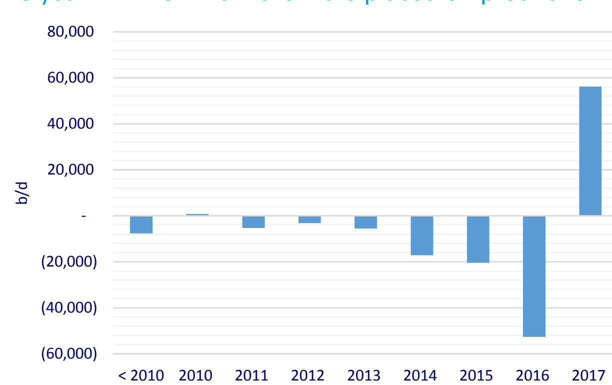
The Permian has become the epicenter of US drilling activity and is one of the few regions where there is differentiated service pricing.

Figure 22: Permian oil production by the year in which the wells were placed on production



Source: Drilling Info, Deutsche Bank

Figure 23: Permian monthly change in oil production by the year in which the wells were placed on production



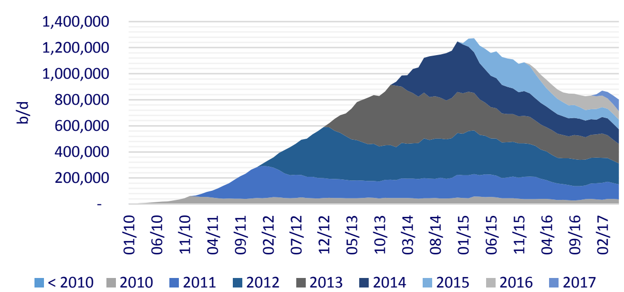
Source: Drilling Info, Deutsche Bank

Does this make the Permian the only game in town?

The US is a bigger threat if there is a broader contribution of oil supplies. Thus far the Permian has contributed the lion's share of the restored oil production with the Eagle Ford only now showing signs of recovery. With two-thirds of the Permian output coming from wells that were placed on production within the last three-years, the revival of US oil production since the lows is somewhat vulnerable to the hyper-decline phases these wells are in. We estimate the Permian needs to replace about 110 kb/d (and growing) from wells brought online before 2017. Wells placed on production in 2017 are contributing in excess of 300 kb/d, which is clearly sufficient and still enough to cover the losses thus far from the Eagle Ford and the Bakken.

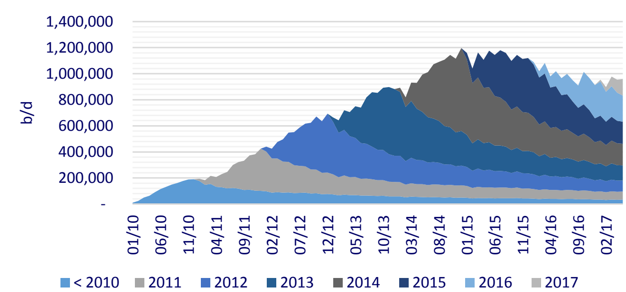
We expect the 40+ rigs added to the Eagle Ford since June 2016 will add about 200 kb/d of oil production by year-end 2017. Wells placed on production prior to 2017 are currently declining by about 55 kb/d and growing. We expect the Eagle Ford data which comes at a lag to show a positive pivot in August. The Bakken is not keeping up in terms of activity. While the drawdown of DUCs contributed more than 100 kb/d, less than 30 rigs returned to work in the Bakken, which sets it up for small declines through year-end.

Figure 24: Eagle Ford oil production by well vintage



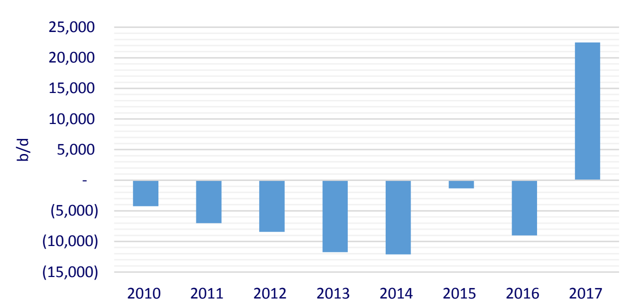
Source: Drilling Info, Deutsche Bank

Figure 25: Bakken oil production by well vintage



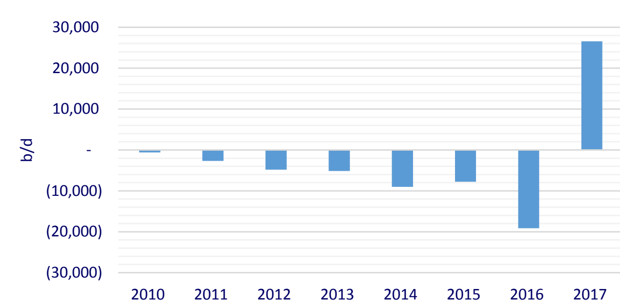
Source: Drilling Info, Deutsche Bank

Figure 26: Eagle Ford monthly change in oil production by year in which wells were placed in production



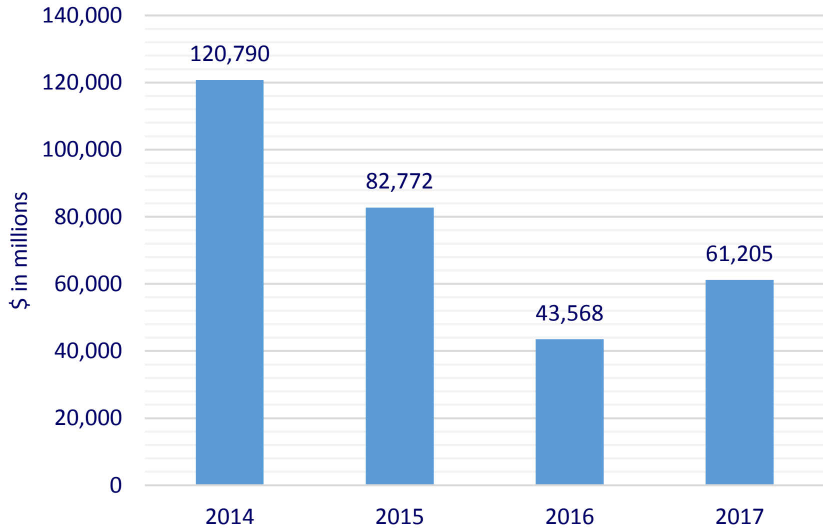
Source: Drilling Info, Deutsche Bank

Figure 27: Bakken monthly change in oil production by year in which wells were placed in production



Source: Drilling Info, Deutsche Bank

Figure 28: US upstream capex guidance for 2017



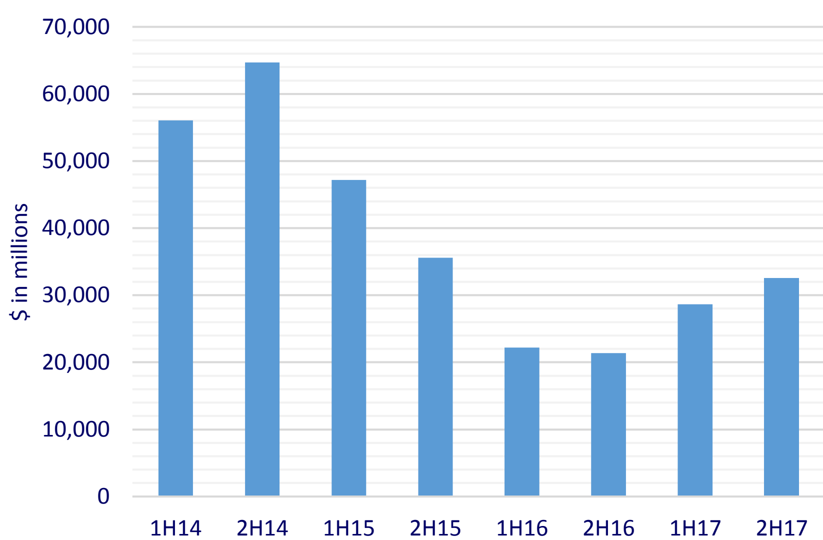
Source: Company reports from some of the top 36 most active producers

The 100+ rig count decline is not in our forecast through year-end

There has been a great deal of speculation that the US rig count was going to lose 100+ rigs into year-end. We expect US producers will have small 2H17 capex revisions, but nothing that triggers a significant slide in activity. Any declines we see are also likely to be more gradual, especially now that oil prices have rebounded.

Currently US budget plans take annual capex up 40% in 2017 versus 2016. This implies a 14% increase in 2H17 versus 1H17.

Figure 29: Small downside risk to 2H17 implied guidance



Source: Company reports from some of the top 36 most active US producers

2018 Rig Count Outlook Weighed Down by Oil Prices

Figure 30: Rig count forecast (DBe)

Rig count forecast	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	(e) 3Q17	(e) 4Q17	2016	(e) 2017	(e) 2018
United States											
Oil-directed rigs	427	315	374	449	573	699	746	735	391	688	744
Gas-directed rigs	108	82	85	117	148	174	182	170	98	168	167
Total U.S. land rigs	**535**	**397**	**459**	**565**	**721**	**873**	**928**	**904**	**489**	**856**	**911**
Sequential chg	-26%	-26%	16%	23%	27%	21%	6%	-3%	-48%	75%	6%
Gulf of Mexico	26	23	18	22	20	21	21	21	22	21	21
Canada	166	48	121	181	295	117	206	300	129	230	241
North America	727	468	598	769	1,036	1,011	1,155	1,225	641	1,107	1,173

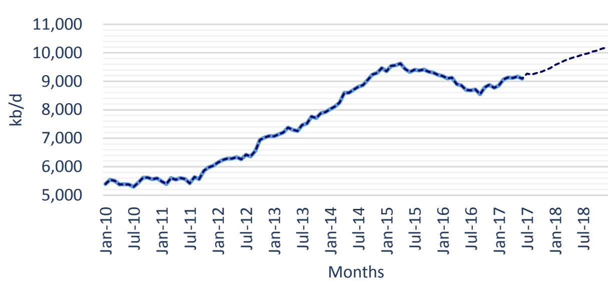
Source: Baker Hughes, a GE Company, Deutsche Bank

The US rig count will likely be obstructed by low oil prices in 2018

We expect the ebb and flow of US upstream capex and the rehabilitation of US productivity to confine oil prices to a range of $45 – 55 through 2018. With the US already on track to realize 9.5 mmb/d of production by year-end 2017, the setup for 2018 is challenging. Our rig count forecast has oil-directed rigs climbing 6% in 2018 versus the 75% increase in 2017. We expect this will keep a lid on service inflation with the exception of hydraulic fracturing, which is poised to return to 2014 demand levels.

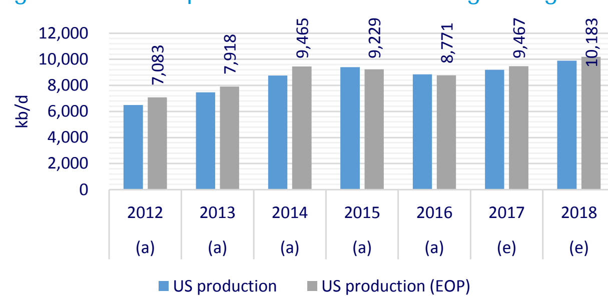
In terms of oil production, we expect the US to grow by 0.7 mmb/d to 10.2 mmb/d by year-end 2018. There will likely be some slower growth periods in 2018 because of a build-up in DUCs. Producers are already waiting for frac equipment that is in the process of being reactivated. Nonetheless, 2018 is setup to be a milestone for the industry as production surpasses the all-time high of 10.0 mmb/d set back in November 1971.

Figure 31: US oil output still rises with slowing rig count



Source: Baker Hughes, a GE Company, Deutsche Bank

Figure 32: US oil production outcome using DB rig count

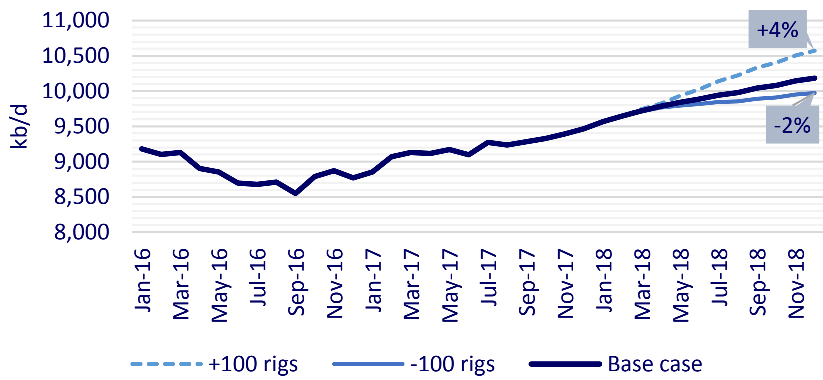


Source: EIA, Deutsche Bank

A 100 rig decline versus our base case would trim 2% off 2018 oil output

We ran a sensitivity analysis of our rig forecast versus our production outcome and found that a 100 rig decline through year-end 2017 would trim 2% from our base case by year-end 2018. The addition of 100 rigs would add 4%. In large scale tight oil developments, rig additions tend to add more upside than subtractions do downside, assuming gradual increases in productivity.

Figure 33: US oil production outcomes using +/- 100 rigs versus DB base case



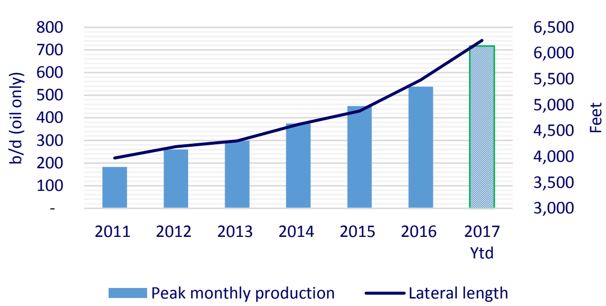
Source: Deutsche Bank, EIA

Can well productivity and service intensity continue to improve?

Enhancements in drilling efficiency and completion design have been driving a higher cadence of more productive wells for seven consecutive years now. While there are some technical and economic break points that are interfering, and a lot of the heavy lifting has already been done, we believe the underlying trends driving increased reservoir contact will continue to push IPs and EURs higher, but at a slower pace.

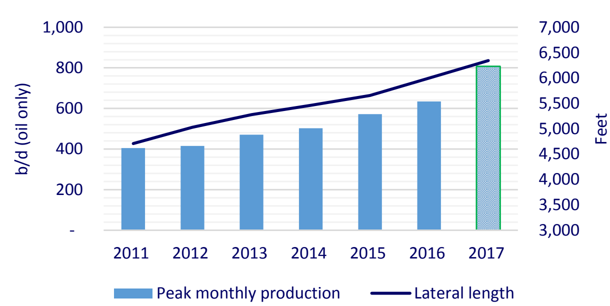
In 2017, there was a jump in 30-day IPs in both the Permian and Eagle Ford. The reason for this was producer mix, not a step change in productivity. While the underlying trends are positive, the lower range in oil prices has curbed the number of producers placing lower quality wells on production. So far, there are 14% fewer producers placing wells on production in the Permian in 2017 versus 2016, and 22% fewer than in 2014. Oil prices above $55 would likely bring some back and lead to more development of lower quality acreage, which would then create a drag on average productivity metrics.

Figure 34: Permian lateral lengths vs. productivity



Source: IHS Markit, Drilling Info, Deutsche Bank

Figure 35: Eagle Ford lateral lengths vs. productivity

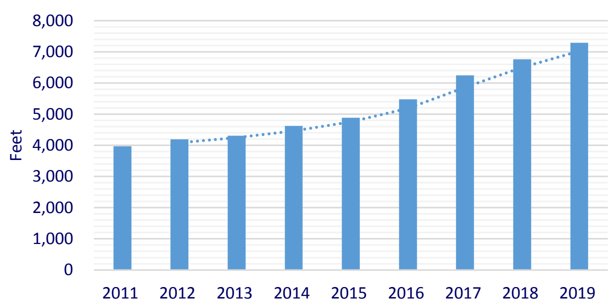


Source: IHS Markit, Drilling Info, Deutsche Bank

Longer laterals to drive further productivity gains despite some interference

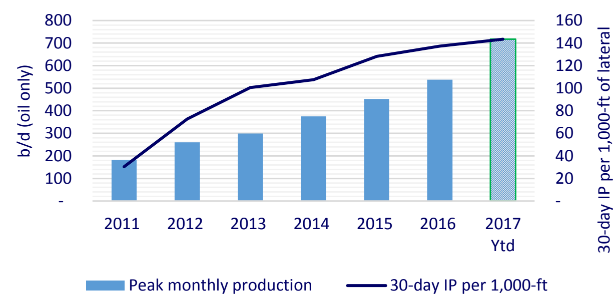
While we are seeing gains in the average 30-day IP per 1,000-ft of lateral slow after years of substantial increases, producers are still extending the overall lateral lengths, which is positive for the services industry. For years we have all questioned the industry on the technical and economic limits of horizontal laterals. Since 2011, the average lateral length has increased by 40% to 6,000-ft. The leading edge is up to 12,000-ft with some experimenting with 20,000+ feet. So far the limitations have been related to limits on friction reducing agents, availability of continuous acreage capable of accommodating longer laterals, and risk. Risk because laterals are drilled open-hole, not cased hole. When laterals extend out to 12,000-ft, costs escalate as does the risk of well integrity. Some smaller, less sophisticated producers are unwilling to take on that risk. But we found that over the last three years, about 50% of the wells placed on production in the Permian and Eagle Ford were drilled by one of the top 30 most active producers, the vast majority of which are pressing ahead with longer laterals.

Figure 36: Average Permian horizontal lateral lengths



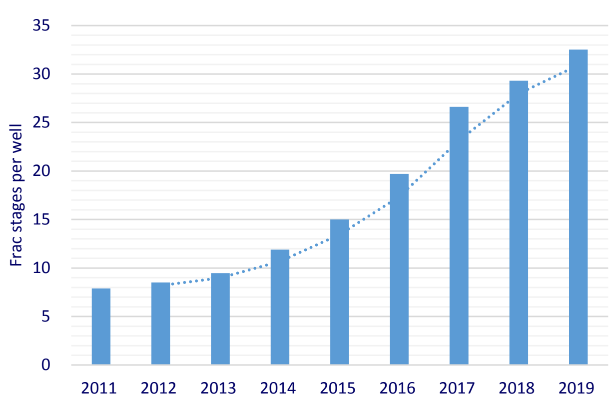
Source: IHS Markit

Figure 37: Average Permian 30-day IPs per 1,000-ft



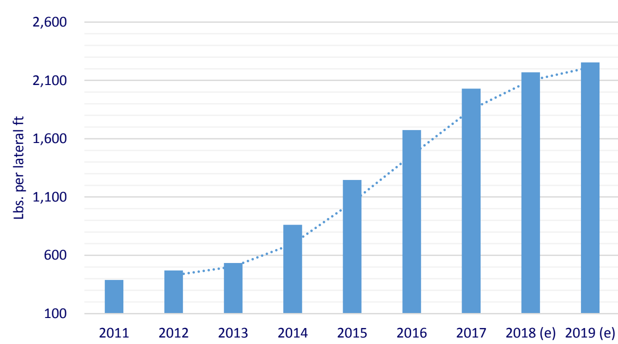
Source: IHS Markit, Drilling Info, Deutsche Bank

Figure 38: Permian frac stages per well



Source: IHS Markit

Figure 39: Permian sand volumes per lateral foot

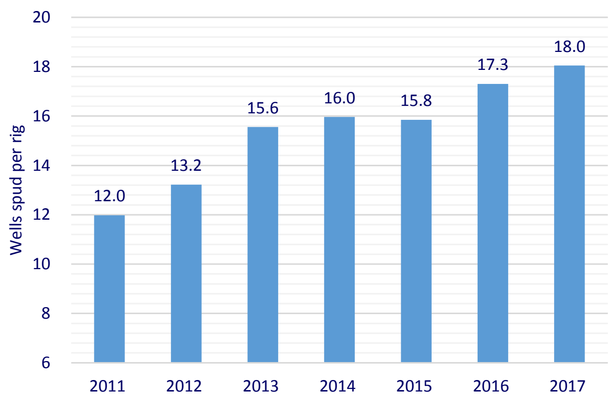


Source: IHS Markit

Land Drilling Darwinism

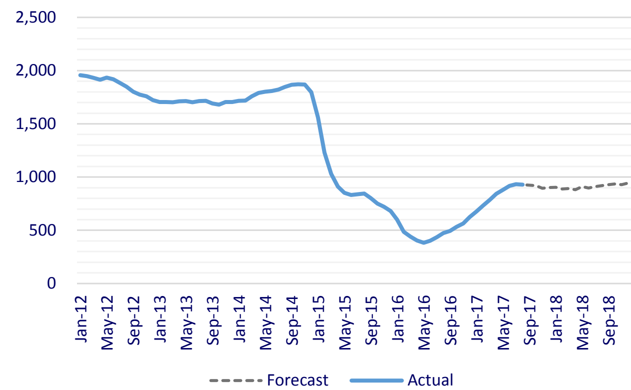
Improved drilling efficiencies and enhanced completions have enabled US producers to drill a higher cadence of more productive wells using fewer rigs. Not only are producers drilling more with less, but now the US is exerting more influence on global oil markets than it has in over 30 years. We believe this will confine oil prices to a range of $45-55 through 2018 and will deflate some of the operating leverage that is customary in the land drilling industry. This is undermining the earnings power of the land drillers, and is forcing key players to devise strategies that will reestablish them in the value chain.

Figure 40: Wells spud per year per rig is up 50%



Source: IHS Markit

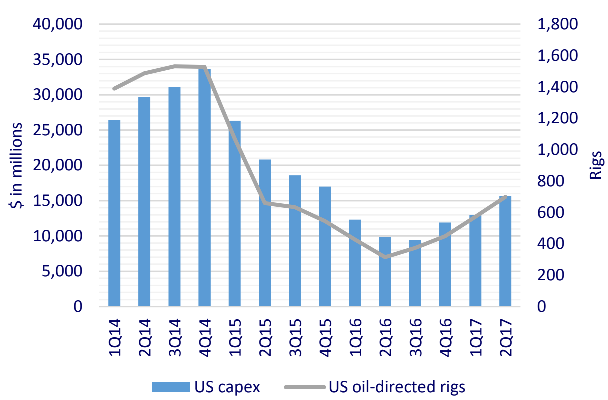
Figure 41: DB rig count forecast



Source: Baker Hughes, a GE Company, Deutsche Bank

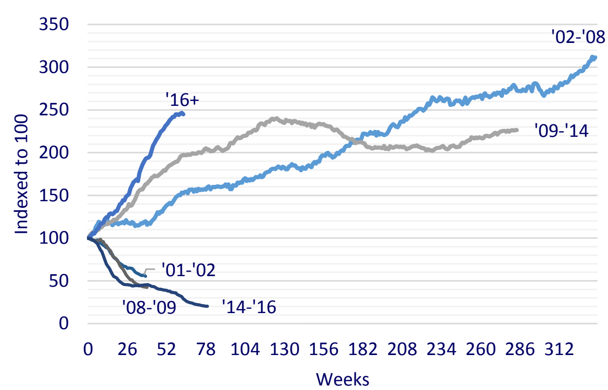
Since the US recovery began in June 2016, the industry has returned about 450 oil-directed rigs to work. It was a quick snap back driven by lower breakeven prices and an inventory of wells with 96% success rates and 3-6 month cash conversions. But we do expect activity to flatten through year-end 2018.

Figure 42: US upstream capex vs. oil-directed rig count



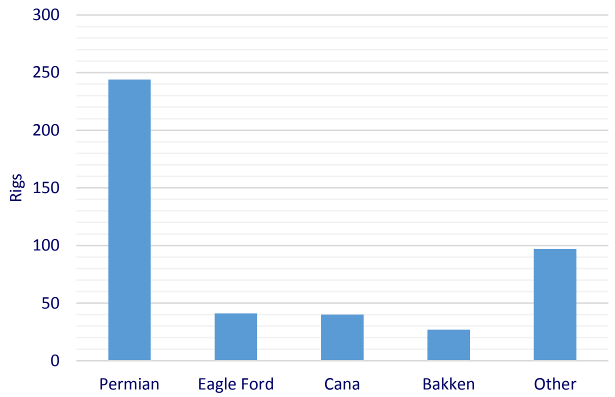
Source: Company reports from the top 36 active US producers, Baker Hughes, a GE Company

Figure 43: We expect recovery to flatten out



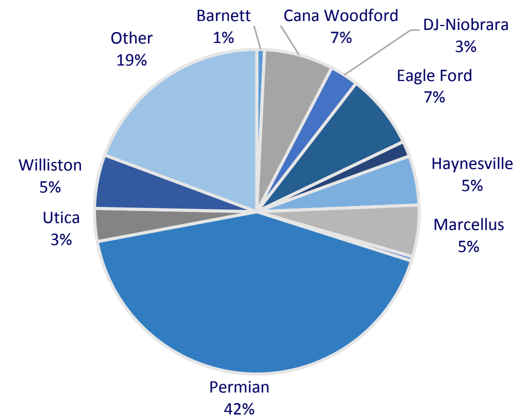
Source: Baker Hughes, a GE Company

Figure 44: Permian is key destination for returning rigs



Source: Baker Hughes, a GE Company

Figure 45: Regional distribution of total US rig count



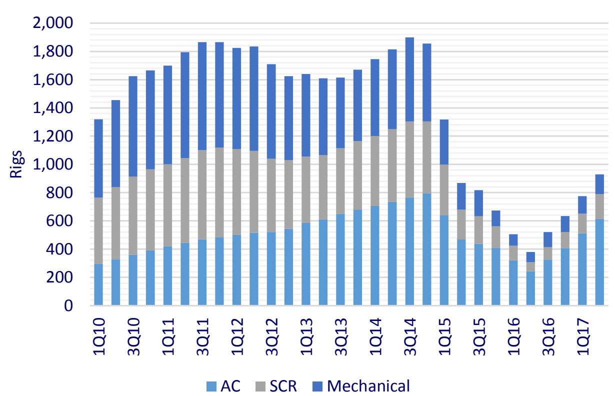
Source: Baker Hughes, a GE Company

A large-scale, industrialized development of tight oil resources

The industry is in the midst of a large-scale, industrialized development of tight oil resources, which creates a high demand for technologies that enable improved drilling efficiencies and lower wells costs. The Permian has become the epicenter of it all, attracting over half of the rigs that have returned to the market since the US recovery began. This has created a bifurcated market where drilling days and pricing are reserved for the preferred 1,500hp AC-electric and super-spec rigs that have leading edge functionality, performance and mobility. HP is the leading provider of super-spec rigs.

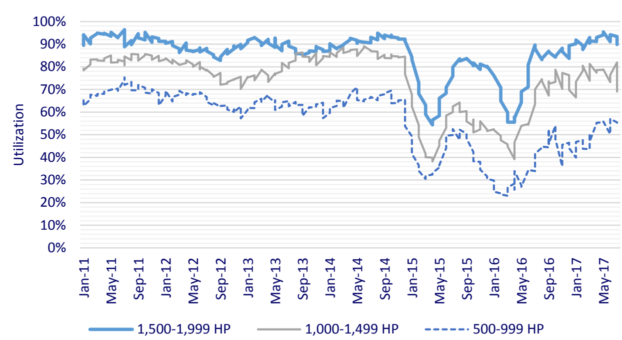
On the other side of the fence are the legacy mechanical and SCR (silicon-controlled rectifier) rig fleets that have endured large scale retirements, but a small population has survived and are still competing for horizontal work.

Figure 46: Producers prefer the 1,500hp AC-electric rigs



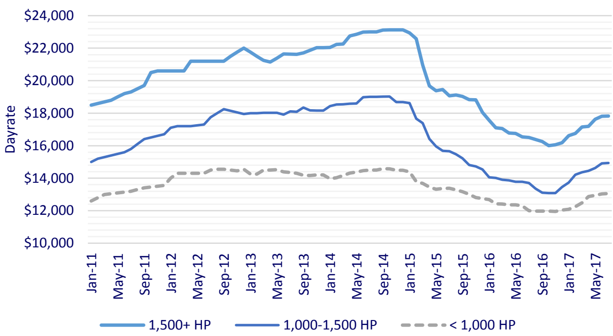
Source: Company reports, IHS Markit, Land Rig Newsletter

Figure 47: Utilization restored for premium rigs



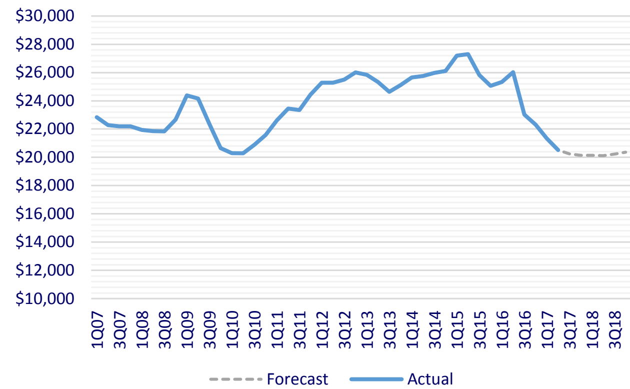
Source: Land Rig Newsletter

Figure 48: Average dayrates across asset classes



Source: Land Rig Newsletter

Figure 49: Average realized dayrate assumptions



Source: Deutsche Bank, includes HP, PTEN, NBR and PDS

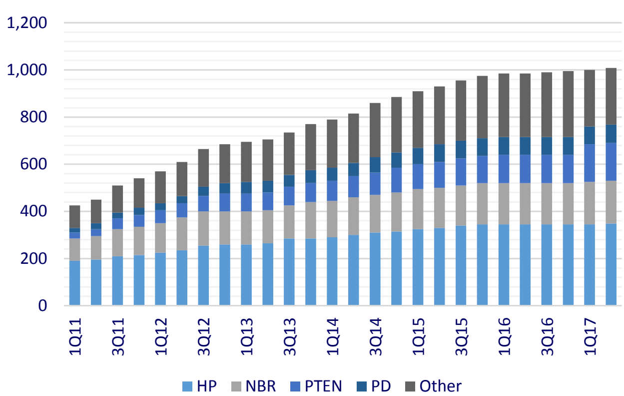
The pricing leverage customary in land drilling will be deflated in 2018

While we have seen a bounce in the average pricing for 1,500hp AC-electric rigs from $16 kpd to $18 kpd, with leading edge at $20-22 kpd, pricing traction is slowing. Utilization for 1,500hp AC-electric rigs is above 90% and producers are saying there is a very limited selection of high-specification rigs left, but we expect the subdued level of activity in 2018 will keep prices from breaking out to and above the $25 kpd level.

Most contractors do not intend to fund newbuilds in this environment

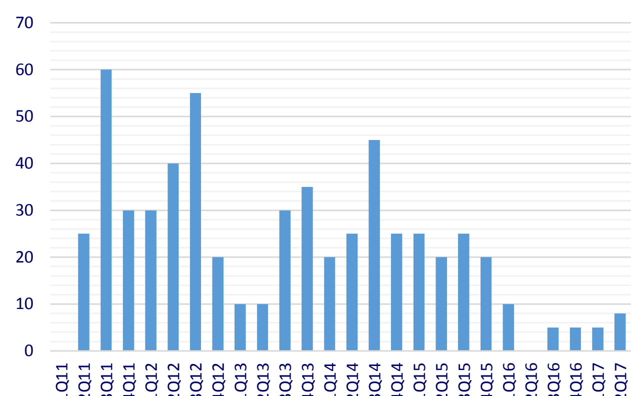
In the late 1990s, HP began rolling out its proprietary FlexRig designs, which were leading edge land rigs with enhanced mobility and faster rates of penetration. The company delivered over 390 of these rigs, mainly in the US, and was able to exploit a significant competitive edge for almost a decade. In the mid-2000s, the peers developed their own proprietary rigs and started their own newbuild programs with some deliveries still in the pipeline.

Figure 50: AC-electric fleet growth



Source: Company reports

Figure 51: Additions of AC-electric rigs



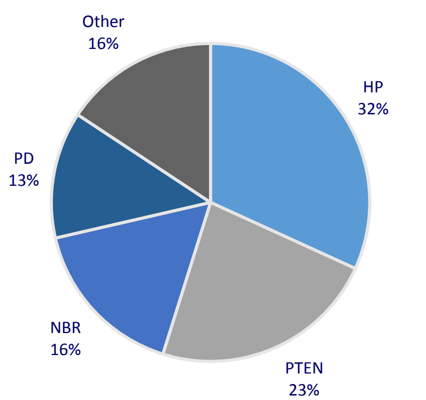
Source: Company reports

But since the collapse in oil prices, the playbook has changed. While the industry continues to demand technology that increases drilling efficiencies and reduces costs, the imbalance in the land rig market is not supporting the $25 kpd dayrate threshold many contractors say is needed to justify newbuilds. With spot rates in the high-teens, the industry is focused on upgrading rigs to super-spec capabilities, which are earning leading edge rates of $20-22 kpd.

The alternative to funding newbuilds is funding upgrades to super-spec

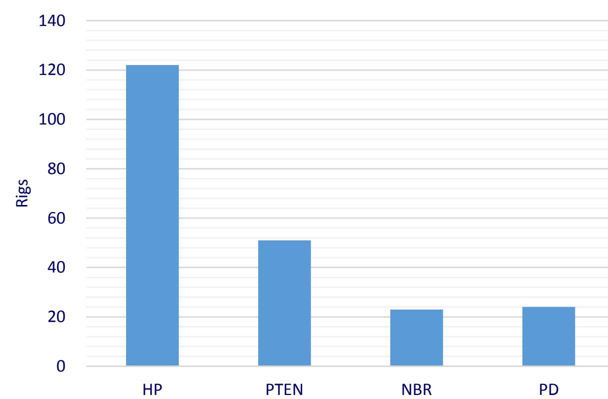
Super-spec rigs are 1,500hp AC-electric rigs that are pad capable, have a third mud pump, a 7,500 psi mud system, a 750k lb. hook load, a fourth engine and a 25,000-ft pipe racking capacity. In essence it is a rig with superior mobility characteristics that enables a producer to drill longer, better quality laterals at a faster rate of penetration, and then move quickly to the next well on the pad. There is high demand for these rigs and producers are paying a $2 kpd premium on 12-24 month contracts to secure access. Utilization of super-spec rigs is now above 90%, but pricing is not acting like utilization is that high.

Figure 52: Super-spec rig market share



Source: Company reports

Figure 53: Inventory of potential upgrades to super-spec



Source: Company reports

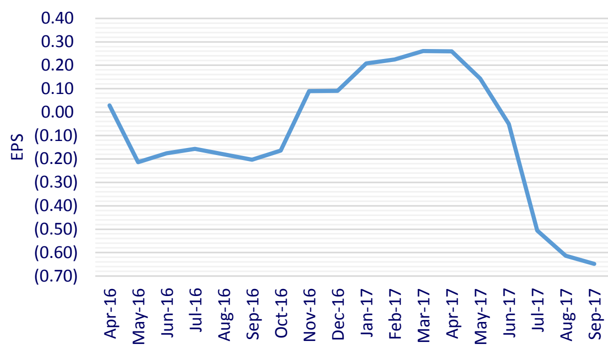
There are varying opinions of how many super-spec rigs there really are, but Patterson-UTI has guided to a fleet of 465 as of 2Q17, which is up from 375 in 4Q16. Helmerich & Payne has the largest market share and the largest inventory of rigs it can upgrade, with 122 candidates that would cost $2-3 million each. Patterson-UTI is currently upgrading seven of its APEX 1000 rigs from the Appalachia region for about $8 million apiece and moving them to west Texas. Nabors has about 23 left as of 2Q17, and intends to complete all of them by early 2018.

Overall, there is the potential to add another 200 super-spec rigs through 2018, which probably has something to do with the less than customary leverage in pricing. But the $2 kpd premium is attracting the upgrade capital, so the question becomes opportunity set. As of August 2017, 26% of the horizontal or directional wells being drilled were done so using mechanical or SCR rigs. Assuming a flat rigs count in 2018, replacing these rigs for performance reasons seems to be the main opportunity.

Encouraging that the consensus acknowledged the EPS vulnerability

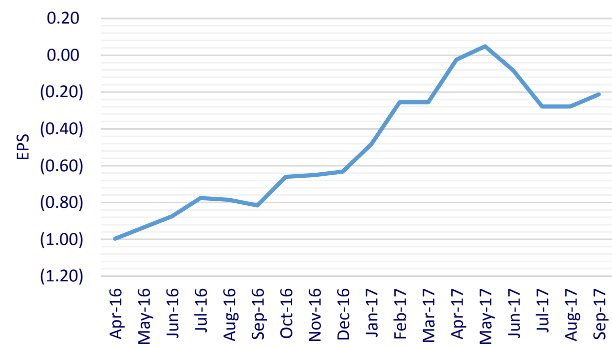
The rapid snap back in the US rig count prompted swift positive EPS revisions because that was the customary course of action. That was discouraging and it stretched out our long-standing negative outlook on the group because in our view the old cyclical playbook was obsolete. The development of tight oil involved a series of disruptive technologies that had derailed the normalization of the cycle. While it created new, more service intense markets (hydraulic fracturing and sand), it also created challenges for markets including land drilling. So it is at least encouraging that expectations have been reset lower. The standout is PTEN, which because of its shift in revenue mix toward frac, the company rightfully is maintained a strong earnings growth outlook.

Figure 54: HP 2018 EPS revisions



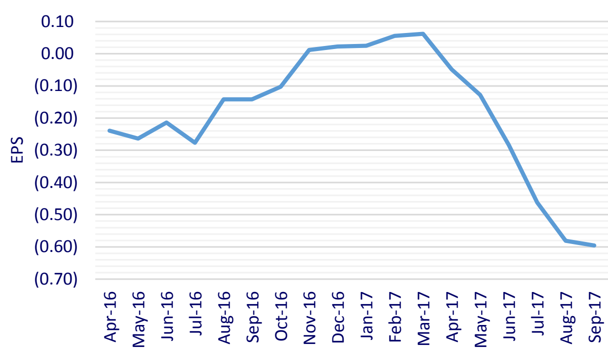
Source: Factset

Figure 55: PTEN 2018 EPS revisions



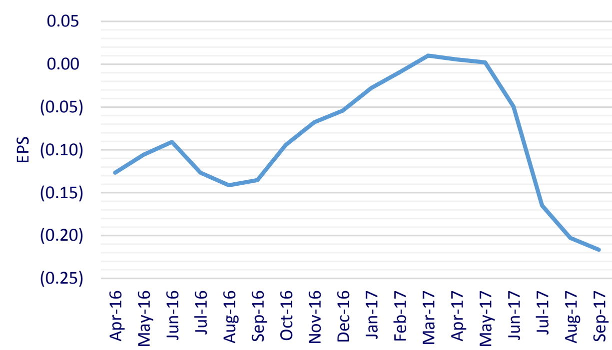
Source: Factset

Figure 56: NBR 2018 EPS revisions



Source: Factset

Figure 57: PDS 2018 EPS revisions

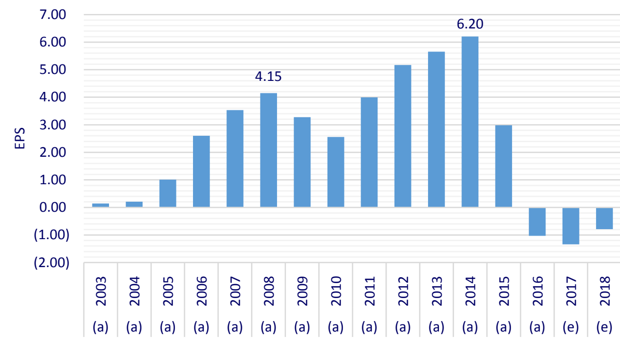


Source: Factset

Earnings power has been in a longer-term down trend

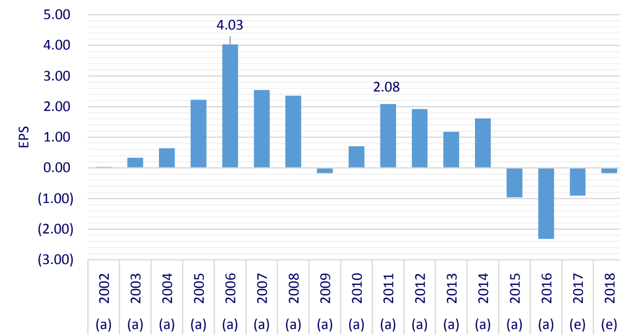
With the exception of HP, the top North American land drillers have been experiencing a long-term erosion in earnings power. We expect this cycle to take it another leg down for the group in terms of peak earnings achieved, with the most resilient being PTEN because of its increased exposure to the frac market.

Figure 58: HP annual EPS



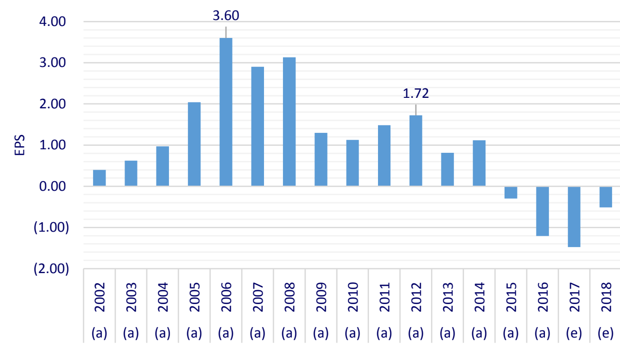
Source: Company reports, Deutsche Bank

Figure 59: PTEN annual EPS



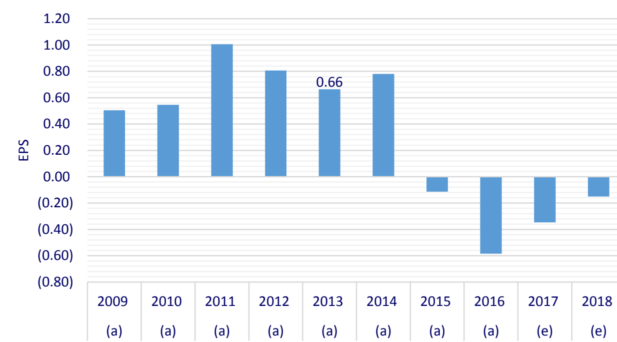
Source: Company reports, Deutsche Bank

Figure 60: NBR annual EPS



Source: Company reports, Deutsche Bank

Figure 61: PDS annual EPS

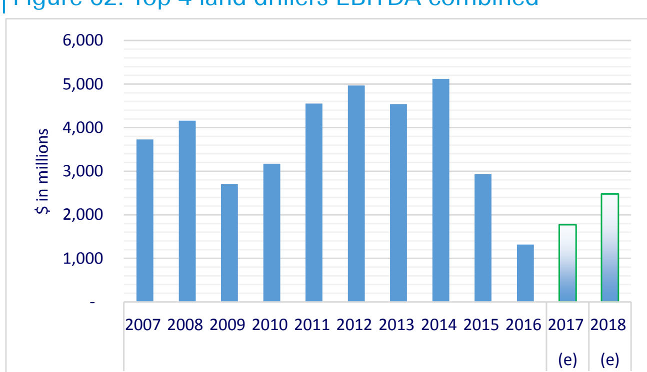


Source: Company reports, Deutsche Bank

PTEN's leverage to frac market embeds more operating leverage to cycle

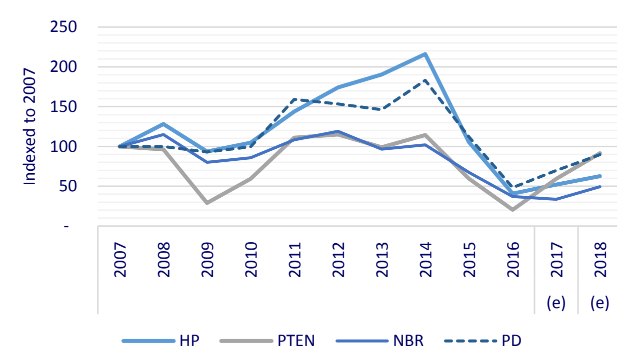
While HP had remarkable growth through 2014, this cycle is likely to deflate its leverage more so than its peers. All four are devising strategies to rejuvenate earnings, and HP is so far focusing on market share while the others, especially Nabors, are adding service content to extract more value per rig.

Figure 62: Top 4 land drillers EBITDA combined



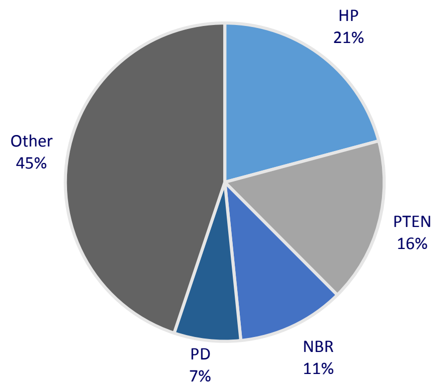
Source: Company reports, Deutsche Bank

Figure 63: PTEN has retained most EBITDA leverage



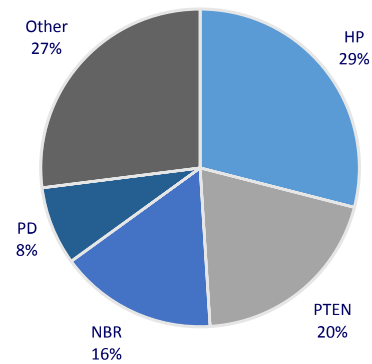
Source: Company reports, Deutsche Bank

Figure 64: Total US land drilling market share



Source: Company reports, Deutsche Bank

Figure 65: AC rig market share



Source: Company reports, Deutsche Bank

Emerging trends

Producers are focused on lowering well costs, drilling wells faster, and increasing reservoir contact. They are tailoring drilling programs to harvest core acreage to fast track cash flow. Ultimately producers are striving for increasingly higher IPs and EURs per F&D dollar invested as the call for capital discipline gets louder. That means there is high demand for technologies that improve rig functionality and performance for:

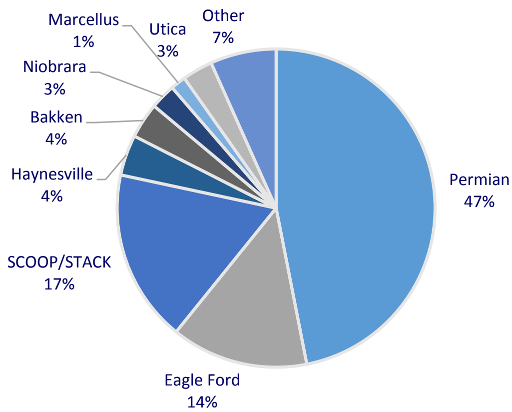
- Mobility (pad drilling)
- Rates-of-penetration (ROP)
- Tripping performance
- Precision well placement

Drilling contractors are focused on competitive positioning. They are achieving this through improving rig functionality, performance and mobility. The key enablers for industrialized resource development are efficiency, reduced costs, technology and scale. Every step is measurable, benchmarked, and improved. As such, contractors are emphasizing their technology and applications that enable drilling automation and machine learning. They are increasing service content to extract more value from their installed base of rigs. Some of the core disciplines in focus are:

- Tubular running services (TRS)
- Directional drilling, measurement-while-drilling (MWD)
- Managed pressure drilling (MPD)

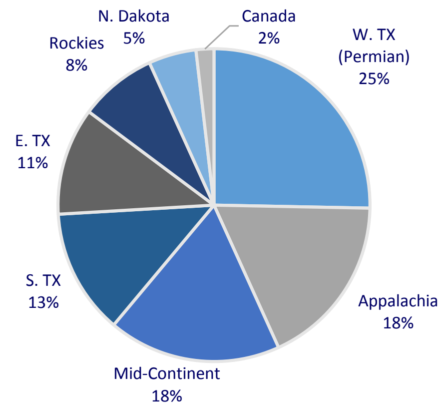
In the long run, full drilling automation is the objective. Nabors has introduced the SMARTRig and the iRIG with the intention of bringing full automation to the industry. Schlumberger has thrown its hat in the ring with its own land rig design for which it plans to extract increasingly more drilling efficiencies and value from the land rig.

Figure 66: HP regional rig exposure



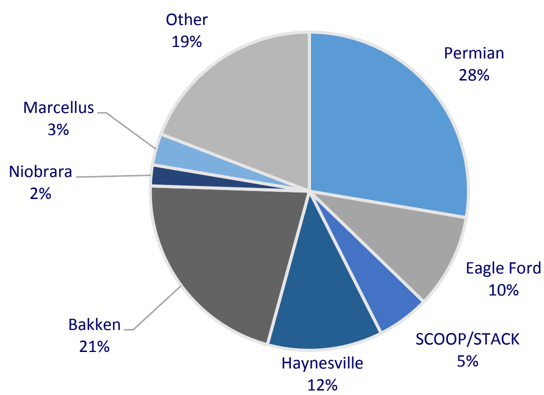
Source: Company reports

Figure 67: PTEN regional rig exposure



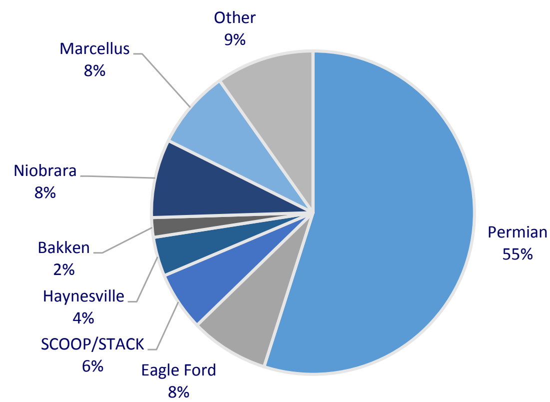
Source: Company reports

Figure 68: NBR regional rig exposure



Source: Bloomberg Finance LP

Figure 69: PDS regional rig exposure

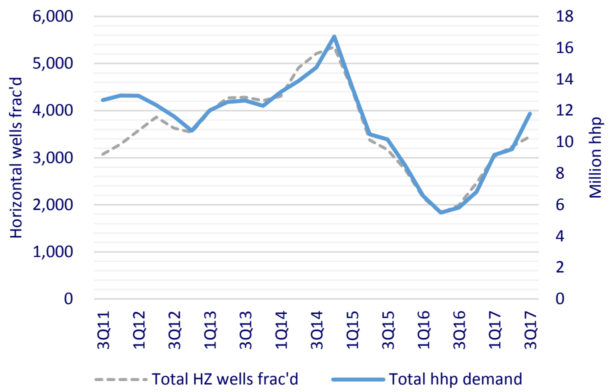


Source: Bloomberg Finance LP

Hydraulic Fracturing

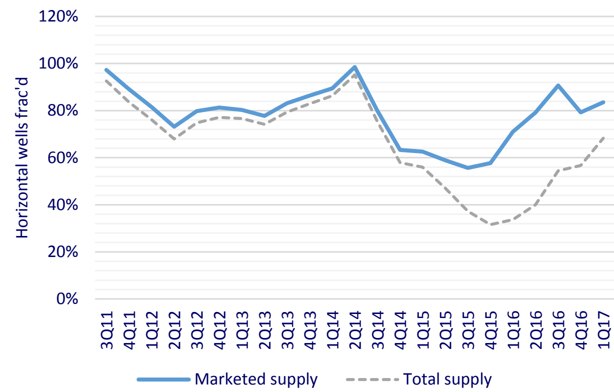
Hydraulic fracturing in the US is one of the very few service disciplines that is undersupplied with some pricing traction. There have been a confluence of trends leading the industry here including a higher penetration of pad drilling, longer laterals, tighter stage spacing, more frac clusters and higher sand loadings, which have all contributed to the need for more horsepower staying on location longer. The average frac spread has increased from about 40k hydraulic horsepower (hhp) to 50k hhp to compensate for maintenance rotations on multi-well pads. The industry has also experienced a higher cadence of wells per rig, which is a trend that appears to be slowing though.

Figure 70: Horizontal wells vs. frac demand



Source: IHS Markit, Deutsche Bank

Figure 71: Total and marketed frac utilization



Source: IHS Markit, Deutsche Bank

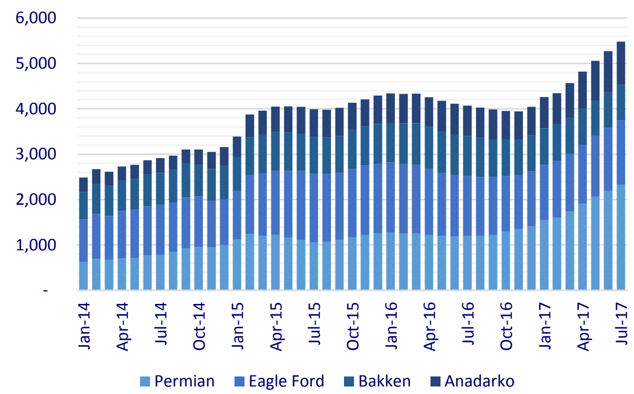
Active frac capacity is booked through year-end 2017

The rapid recovery in drilling activity that began in June 2016 combined with an initial drawdown of drilled but uncompleted wells (DUCs) at the onset of the oil price inflection (largely in the Bakken) has pushed the demand for hydraulic fracturing up to 12 million hhp from the low of 6 million in early 2016. Marketed utilization has risen above 80% from about 58% with pricing pivoting in 4Q16. Most of the major frac companies are indicating fully booked frac calendars through year-end 2017 with some contractors suggesting the market is currently undersupplied by about 1.5–2.0 million hhp. Attrition is also picking up with some managements suggesting it is as high 3.5 million hhp per year. The key driver is the increased job intensity that is chewing up the equipment faster and reducing the useful life, which means maintenance capex is rising.

Price inflation in frac is leading other service disciplines

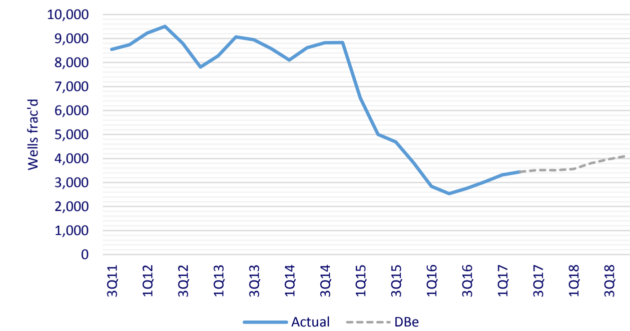
There is pricing power, but it is modest relative to the tightness in the market. The reason being is the available hhp that is being reactivated through year-end and into early 2018. While some companies suggest pricing does not justify newbuilds yet, there is at least 1.0 million hhp that has been ordered already and costs are back up to $1,000/hhp. Newbuild lead times are currently 9-12 months for most except HAL, which can launch equipment in a month.

Figure 72: DUCs rising again due to frac bottleneck



Source: EIA

Figure 73: US onshore wells frac'd

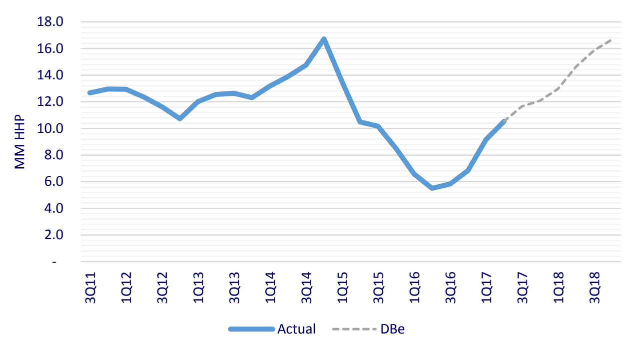


Source: IHS Markit , Deutsche Bank

Frac demand is poised to recover to the 2014 highs

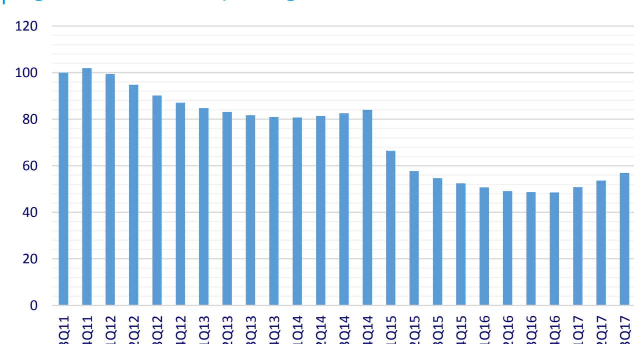
Despite our flat rig count outlook for 2018, the demand for frac hhp continues to move higher, exiting 2018 near the 2014 highs in our view. With producers tailoring their rig programs to focus increasingly on their core acreage with optimized completion designs for maximized reservoir contact, the average lateral lengths, stage densities, and sand loadings are all moving higher on pads that are slowly getting larger. Producers are effectively concentrating their existing rig count on their larger, more productive wells, thus the call on frac demand is disproportionately higher now than it was in 2014 when only about 55-60% of the rigs working were focused on optimized development drilling. The rest were doing hold-by-production, exploration or delineation drilling.

Figure 74: US hydraulic horsepower demand



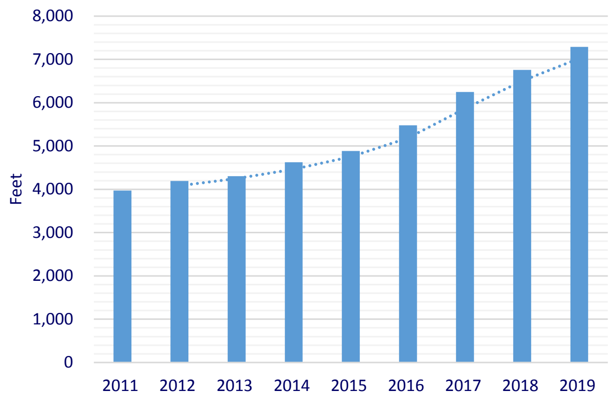
Source: IHS Markit, Deutsche Bank

Figure 75: US frac pricing indexed to 100 at 3Q11



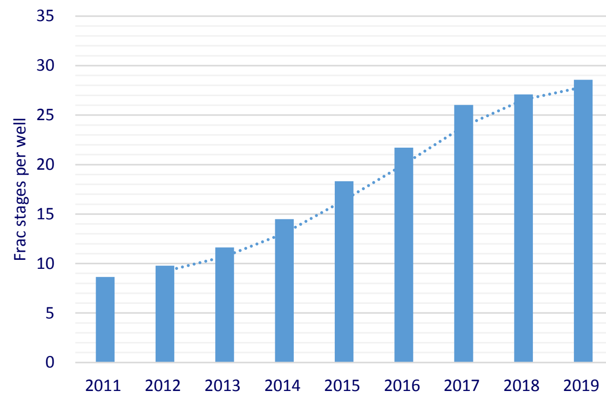
Source: IHS Markit, Deutsche Bank

Figure 76: Average Permian horizontal lateral lengths



Source: IHS Markit

Figure 77: Average US frac stages per well

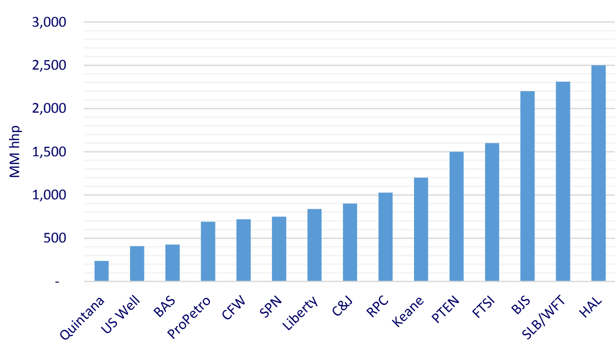


Source: IHS Markit

Still a fragmented market

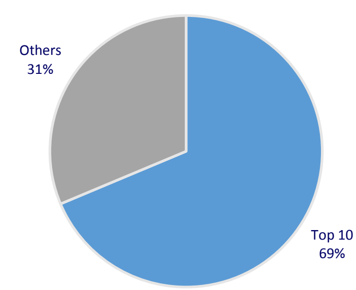
Halliburton is still the largest US frac provider with about 13% market share followed by the OneStim JV between Schlumberger and Weatherford. In terms of concentrated earnings exposure, C&J Energy, RPC, Patterson and Superior Energy have the highest bottom line exposures within our coverage universe.

Figure 78: Top US frac providers



Source: IHS Markit, Deutsche Bank

Figure 79: US market share of top 10 frac companies



Source: IHS Markit, Deutsche Bank

Bakken

Figure 80: Leading edge production

Production	
Oil	985 kb/d
Gas	1,783,431 MCF/d

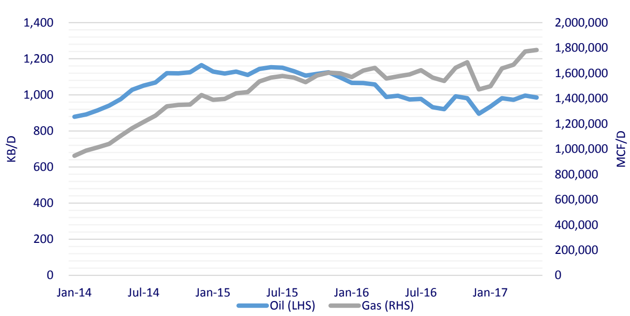
Source: dmr.nd.gov

Figure 81: Current activity levels

Rig Count	
Oil	49
Gas	0
Total	49

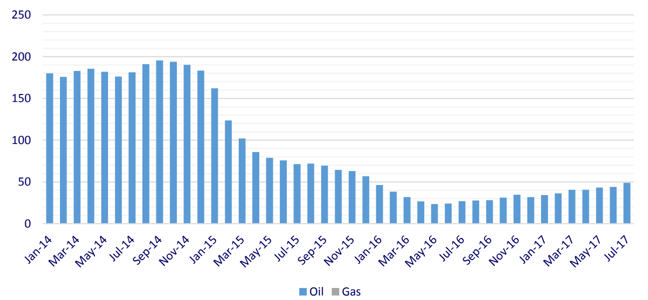
Source: Baker Hughes, a GE Company

Figure 82: Production



Source: dmr.nd.gov

Figure 83: Rig count



Source: Baker Hughes, a GE Company

Figure 84: Top operators

2017 Production (mboe/d)	Active Rig Count
1. Continental Resources	1. Oasis Petroleum
2. Whiting Petroleum Corporation	2. Marathon Oil
3. Hess Corporation	3. Continental Resources
4. ExxonMobil	4. ConocoPhillips
5. Crescent Point	

Source: Wood Mackenzie, RADAR

Figure 85: Land rig market leaders

Top Rig Contractors	Mkt Share
1. Nabors	37%
2. Patterson UTI	16%
3. Helmerich & Payne	14%
4. Cyclone Drilling	6%

Source: RADAR

Figure 86: Regional frac fundamentals

Pressure Pumping	Active	Warm-stack	Cold-stack	Total
HHP	567,250	209,000	75,000	851,250
Spreads	20	9	3	32
			Utilization	**67%**

Source: IHS markit

Figure 87: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. Schlumberger	19%
2. Liberty Oilfield Services	14%
3. Calfrac Well Services	12%
4. Keane Group	12%
5. Halliburton	10%

Source: IHS markit

DJ Niobrara

Figure 88: Leading edge production

Production	
Oil	450 kb/d
Gas	4,611,182 MCF/d

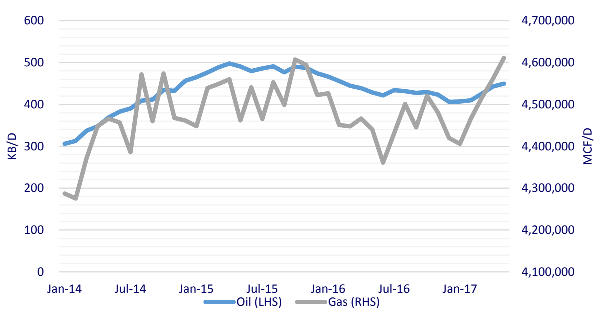
Source: EIA

Figure 89: Current activity levels

Rig Count	
Oil	26
Gas	0
Total	26

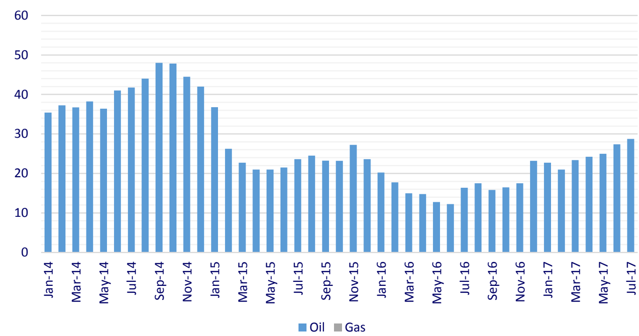
Source: Baker Hughes, a GE Company

Figure 90: Production



Source: EIA

Figure 91: Rig count



Source: Baker Hughes, a GE Company

Figure 92: Top operators

2017 Production (mboe/d)	Active Rig Count
1. Anadarko	1. Anadarko
2. Noble Energy	2. PDC Energy
3. PDC Energy	3. Noble Energy
4. Bonanza Creek Energy	4. Crestone Peak Resources
5. Synergy Resources	

Source: Wood Mackenzie, RADAR

Figure 93: Land rig market leaders

Top Rig Contractors	Mkt Share
1. Ensign USA	27%
2. Precision Drilling	19%
3. Xtreme Drilling	15%
4. Helmerich & Payne	12%

Source: RADAR

Figure 94: Regional frac fundamentals

Pressure Pumping				
	Active	Warm-stack	Cold-stack	Total
HHP	623,000	126,000	0	749,000
Spreads	19	3	0	22
			Utilization	83%

Source:IHS markit

Figure 95: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. Halliburton	41%
2. Liberty Oilfield Services	20%
3. Calfrac Well Services	15%
4. C&J Energy Services	12%
5. Basic Energy Services	7%

Source: IHS markit

Eagle Ford

Figure 96: Leading edge production

Production	
Oil	981 kb/d
Gas	2,375,125 MCF/d

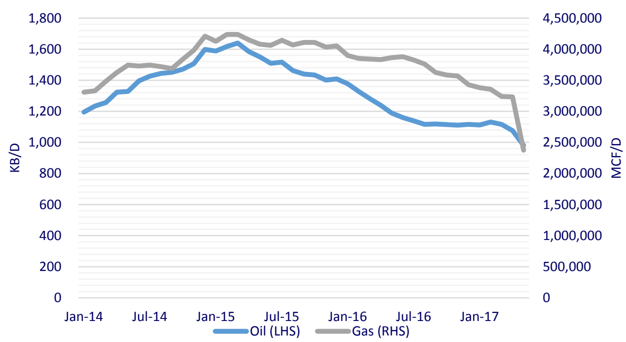
Source: Texas RRC

Figure 97: Current activity levels

Rig Count	
Oil	60
Gas	8
Total	68

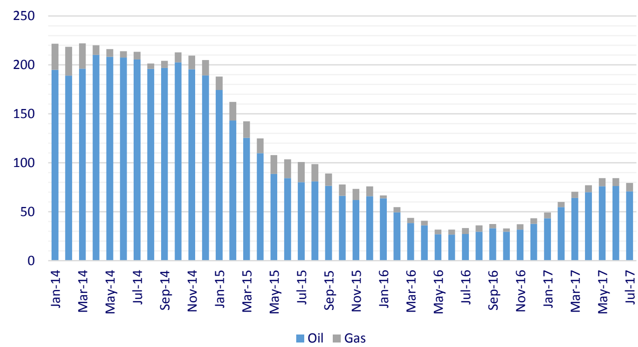
Source: Baker Hughes, a GE Company

Figure 98: Production



Source: Texas RRC

Figure 99: Rig count



Source: Baker Hughes, a GE Company

Figure 100: Top operators

2017 Production (mboe/d)	Active Rig Count
1. EOG Resources	1. EOG Resources
2. ConocoPhillips	2. Chesapeake Energy
3. Marathon Oil	3. ConocoPhillips
4. Chesapeake Energy	4. Sanchez Oil & Gas
5. Sanchez Energy Corporation	

Source: Wood Mackenzie, RADAR

Figure 101: Land rig market leaders

Top Rig Contractors	Mkt Share
1. Helmerich & Payne	35%
2. Patterson UTI	28%
3. Nabors Industries	14%
4. Precision Drilling	6%

Source: RADAR

Figure 102: Regional frac fundamentals

Pressure Pumping	Active	Warm-stack	Cold-stack	Total
HHP	1,665,000	278,000	375,500	2,318,500
Spreads	42	7	9	58
			Utilization	**72%**

Source: IHS markit

Figure 103: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. Universal (PTEN)	18%
2. Schlumberger	16%
3. Halliburton	14%
4. FTS International	13%
5. Calfrac Well Services	8%

Source: IHS markit

Haynesville

Figure 104: Leading edge production

Production	
Oil	45 kb/d
Gas	6,296,425 MCF/d

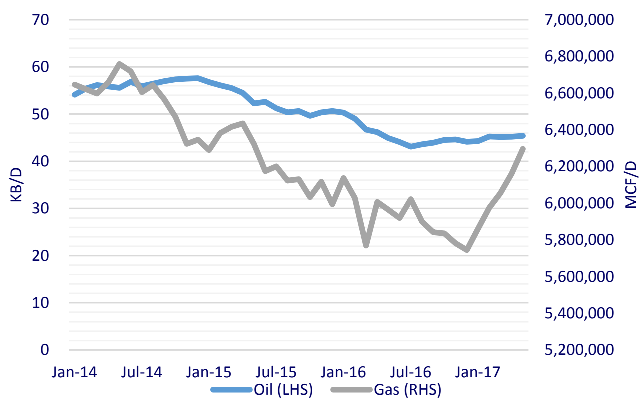
Source: EIA

Figure 105: Current activity levels

Rig Count	
Oil	2
Gas	43
Total	45

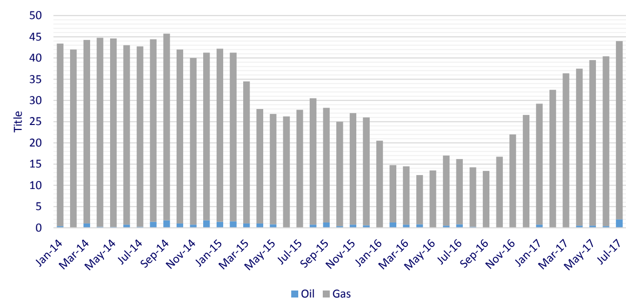
Source: Baker Hughes, a GE Company

Figure 106: Production



Source: EIA

Figure 107: Rig Count



Source: Baker Hughes, a GE Company

Figure 108: Top operators

2017 Production (mboe/d)	Active Rig Count
1. Chesapeake Energy	1. Indigo Minerals
2. Range Resources Corp	2. GEP Haynesville
3. ExxonMobil	3. EXCO Resources
4. BHP Billiton	4. Comstock Resources
5. GeoSouthern Energy	

Source: Wood Mackenzie, RADAR

Figure 109: Land rig market leaders

Top Rig Contractors	Mkt Share
1. Nabors Industries	25%
2. Patterson UTI	21%
3. Independence Contractors	14%
4. Helmerich & Payne	14%

Source: RADAR

Figure 110: Regional frac fundamentals

Pressure Pumping	Active	Warm-stack	Cold-stack	Total
HHP	478,000	130,000	0	608,000
Spreads	9	2	0	11
			Utilization	**79%**

Source: IHS markit

Figure 111: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. FTS International	41%
2. Cudd Energy Services	21%
3. Halliburton	16%
4. C&J Energy Services	8%
5. BJ Services	7%

Source: IHS markit

Marcellus

Figure 112: Leading edge production

Production	
Oil	40 kb/d
Gas	19,156,560 MCF/d

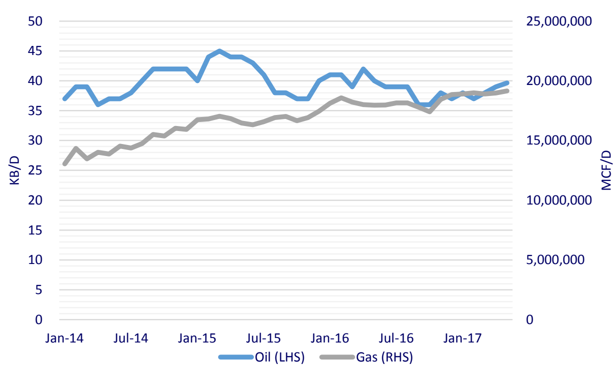
Source: EIA

Figure 113: Current activity levels

Rig Count	
Oil	0
Gas	47
Total	47

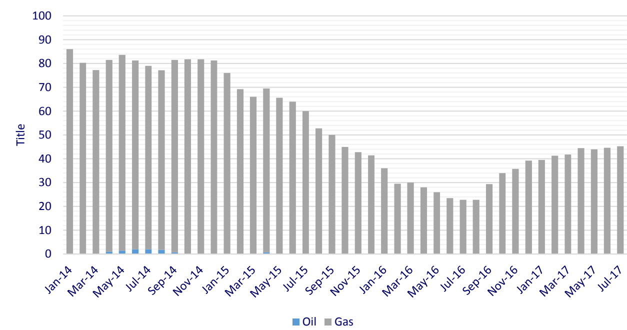
Source: Baker Hughes, a GE Company

Figure 114: Production



Source: EIA

Figure 115: Rig Count



Source: Baker Hughes, a GE Company

Figure 116: Top Operators

2017 Production (mboe/d)	Active Rig Count
1. EQT Corporation	1. EQT Corporation
2. Antero Resources	2. Range Resources
3. Cabot Oil & Gas	3. Rice Energy
4. Southwestern Energy	4. Southwestern Energy
5. Chesapeake Energy	

Source: Wood Mackenzie, RADAR

Figure 117: Land Rig Market Leaders

Top Rig Contractors	Mkt Share
1. Patterson UTI	31%
2. Falcon Drilling	14%
3. Precision Drilling	11%
4. SWN Drilling Co.	9%

Source: RADAR

Figure 118: Regional frac fundamentals

Pressure Pumping	Active	Warm-stack	Cold-stack	Total
HHP	478,000	130,000	0	608,000
Spreads	9	2	0	11
			Utilization	**79%**

Source: IHS markit

Figure 119: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. Universal (PTEN)	19%
2. US Well Services	12%
3. FTS International	11%
4. Keane Group	10%
5. Halliburton	9%

Source: IHS markit

MidCon

Figure 120: Leading edge production

Production	
Oil	433 kb/d
Gas	6,691,000 MCF/d

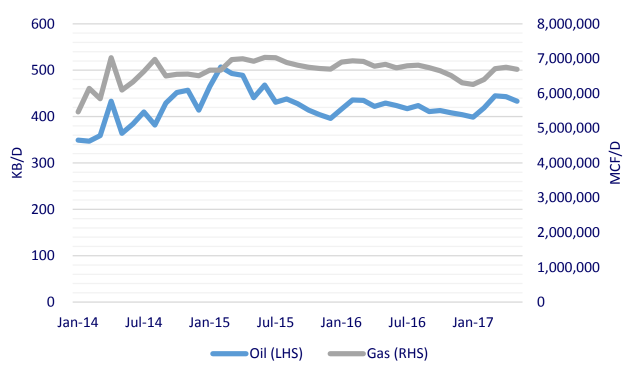
Source: EIA

Figure 121: Current activity levels

Rig Count	
Oil	63
Gas	0
Total	63

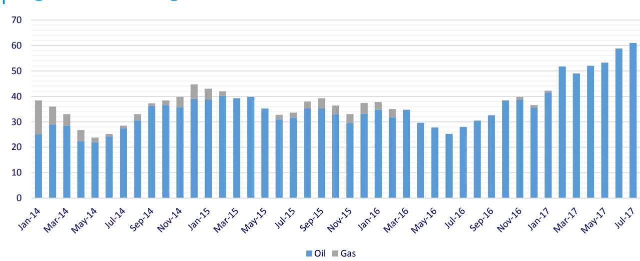
Source: Baker Hughes, a GE Company

Figure 122: Production



Source: EIA

Figure 123: Rig Count



Source: Baker Hughes, a GE Company

Figure 124: Top operators

2017 Production (mboe/d)	Active Rig Count
1. Devon Energy	1. Continental Resources
2. Continental Resources	2. Marathon Oil
3. Newfield Exploration	3. Newfield Exploration
4. Cimarex Energy	4. Devon Energy
5. ExxonMobil	5. Gulfport Energy

Source: Wood Mackenzie, RADAR

Figure 125: Land rig market leaders

Top Rig Contractors	Mkt Share
1. Helmerich & Payne	21%
2. Cactus Drilling	19%
3. Patterson UTI	18%
4. Unit Corp	12%
5. Nabors Industries	6%

Source: RADAR

Figure 126: Regional frac fundamentals

Pressure Pumping	Active	Warm-stack	Cold-stack	Total
HHP	1,151,500	321,150	160,000	1,632,650
Spreads	35	11	5	51
			Utilization	71%

Source: IHS markit

Figure 127: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. Universal (PTEN)	18%
2. Halliburton	11%
3. Quintana Energy Services	10%
4. Basic Energy Services	8%
5. Keane Group	8%

Source: IHS markit

Permian

Figure 128: Leading edge production

Production	
Oil	1,501 kb/d
Gas	1,340,123 MCF/d

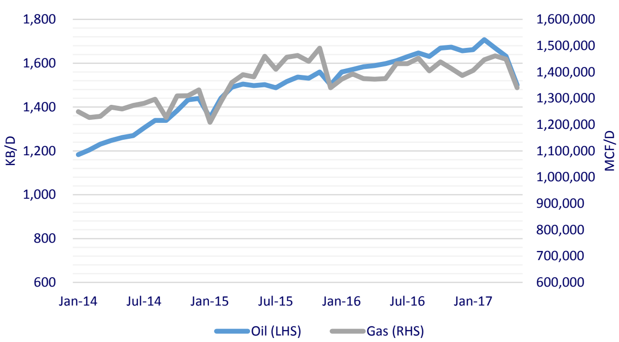
Source: Texas RRC

Figure 129: Current activity levels

Rig Count	
Oil	386
Gas	0
Total	386

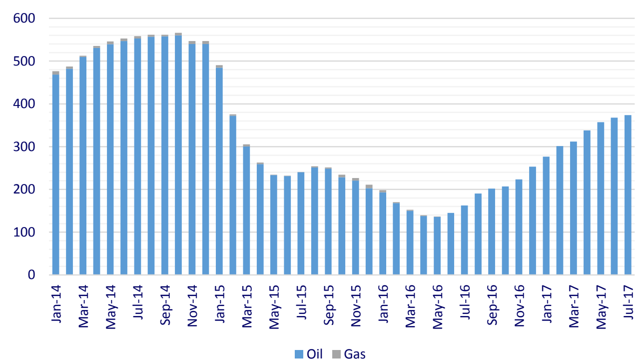
Source: Baker Hughes, a GE Company

Figure 130: Production



Source: Texas RRC

Figure 131: Rig Count



Source: Baker Hughes, a GE Company

Figure 132: Top Operators

2017 Production (mboe/d)	Active Rig Count
1. Occidental Petroleum	1. Pioneer Natural Resources
2. Pioneer Natural Resources	2. Apache Corp
3. Chevron	3. Newfield Exploration
4. Concho Resources	4. Concho Resources
5. Apache Corp	5. Occidental Petroleum

Source: Wood Mackenzie, RADAR

Figure 133: Land rig market leaders

Top Rig Contractors	Mkt Share
1. Helmerich & Payne	23%
2. Patterson UTI	10%
3. Precision Drilling	7%
4. Nabors Industries	7%
5. Trinidad Drilling	6%

Source: RADAR

Figure 134: Regional frac fundamentals

Pressure Pumping				
	Active	Warm-stack	Cold-stack	Total
HHP	3,913,500	595,000	169,000	4,677,500
Spreads	116	21	7	144
			Utilization	**84%**

Source: IHS markit

Figure 135: Frac market leaders

Top Pressure Pumpers	Mkt Share
1. Halliburton	15%
2. ProPetro	11%
3. Schlumberger	8%
4. Keane Group	8%
5.Liberty Oilfield Services	7%

Source: IHS markit

Offshore Drilling Facing Unprecedented Challenges

Deepwater markets are in the midst of a very long transition

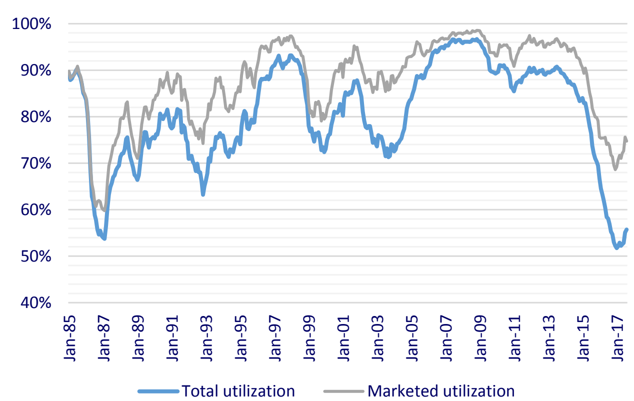
This is the most challenging environment the deepwater drilling industry has ever faced. Over the past three years, the industry has endured an unusually severe decline in rig fixtures, an unprecedented wave of early contract terminations, and a sizeable withdrawal of customers. The supply demand imbalance is unlike anything the industry has ever experienced. Balance sheets are being tested, pricing tactics are fierce, and rigs are being scrapped at a record pace. After all is said and done, the earnings power of the industry has diminished severely and companies are seeking ways to reestablish themselves in the value chain.

But after a long wait, the deepwater market is finding a bottom. Deepwater final investment decisions (FIDs) are finally coming in, breakeven prices are moving lower, and tendering activity is picking up. But the recovery is likely to be slow and laborious. The supply demand imbalance and the balance sheet stresses are going to keep the fierce pricing tactics in play for a number of years in our view.

This will sooner or later reconfigure the industry. We expect M&A will play a major role in the coming months, which presents another quandary. The best companies in terms of fiscal stability, which has been a key investment factor, are also the primary suitors. The apathy in this space will not stop sharp scrutiny on deals. The firmly entrenched negative sentiment may judge each deal as too early, too expensive, and too taxing on the balance sheet. It is unlikely any suitor will get as good of a deal as the market thinks it should.

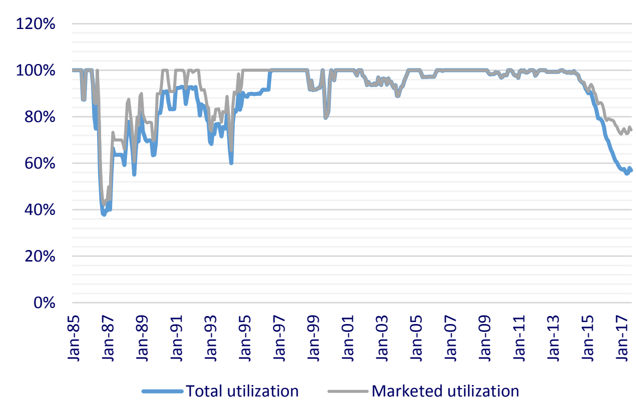
Having said that, we believe Transocean has been ahead of the curve in terms of cash preservation, and its proposed acquisition of Songa Offshore provides the company with $4.1 billion of backlog, $0.7 billion of new annual revenues through 2022, and exposure to one of the key deepwater markets, Norway.

Figure 136: Total floater utilization



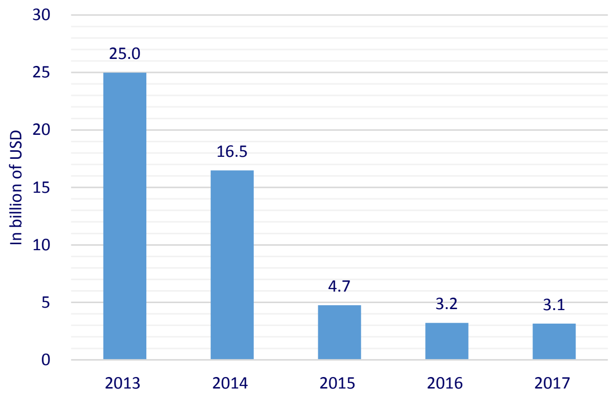
Source: ODS-Petrodata, Deutsche Bank

Figure 137: High-specification floater utilization



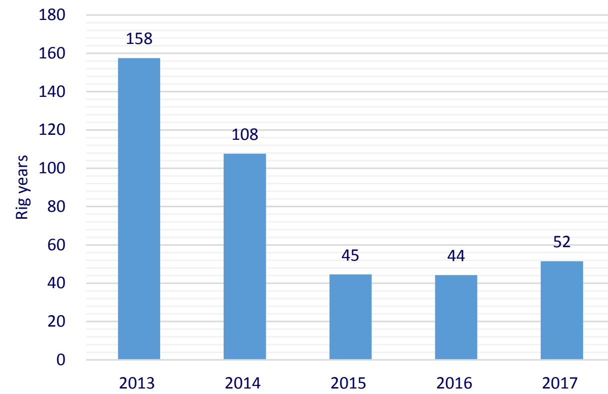
Source: ODS-Petrodata, Deutsche Bank

Figure 138: Floating rig backlog additions have plunged



Source: ODS-Petrodata, Deutsche Bank

Figure 139: Floating rig backlog in rig years improving



Source: ODS-Petrodata, Deutsche Bank

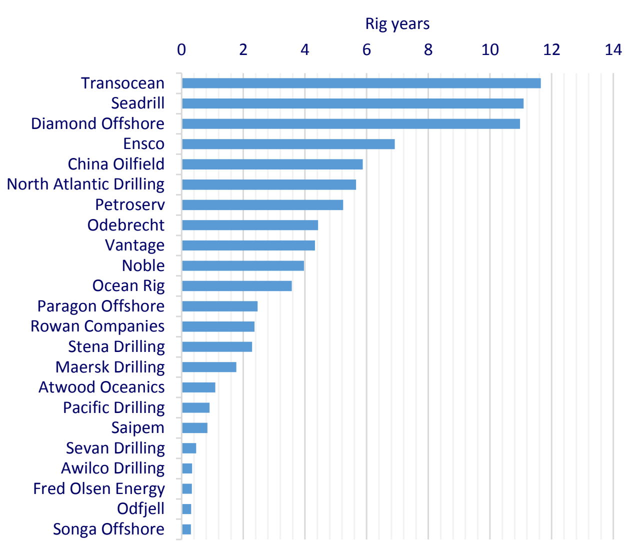
Unusually severe decline in deepwater rig fixtures

The deepwater has experienced downturns, but none that have depressed its book-to-bill to a mere 15% for three consecutive years. In 2014, the industry booked $16.5 billion of backlog for a book-to-bill of 43%. After the fall in oil prices, new fixtures promptly dropped to $4.7 billion in 2015 and $3.2 billion in 2016. Rig years booked have increased in 2017, but near breakeven dayrates have been a drag on the backlog value at just $3.1 billion.

Early contract terminations were a major destabilizing factor

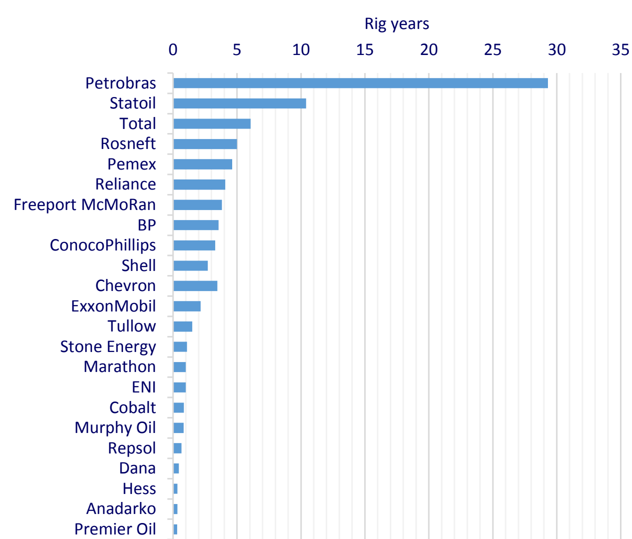
The frequency of early terminations has wound down. Since the peak in 2014, there has been an unprecedented wave of early contract terminations that have totaled 86 rig years and $14 billion in backlog. About $6.9 billion was cancelled in 2015 followed by $6.3 billion in 2016 and only $0.3 billion in 2017.

Figure 140: Early terminations sorted by rig contractor



Source: ODS-Petrodata, Deutsche Bank

Figure 141: Early terminations sorted by operator

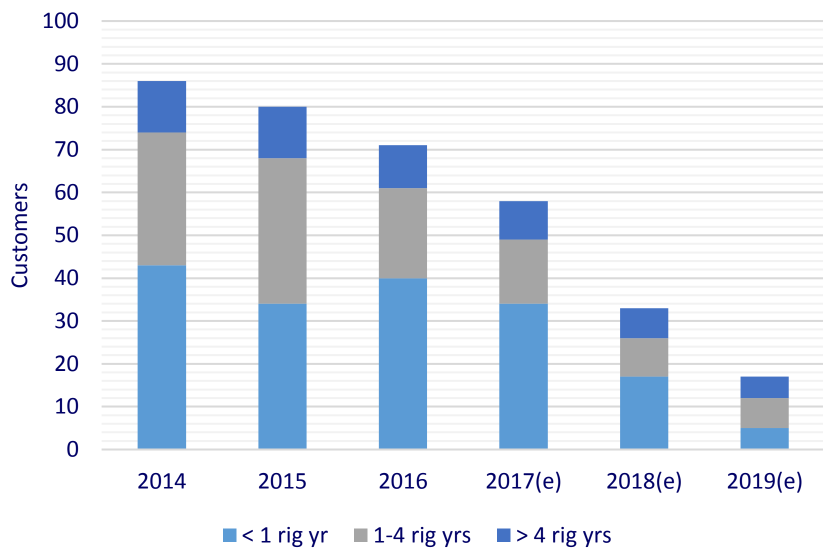


Source: ODS-Petrodata, Deutsche Bank

Sizeable withdraw of customers

The number of operators contracting rigs has fallen significantly and is likely to keep falling in the coming years in our view. There were 86 operators using floaters in 2014, which was a high for the industry. Half had demand only for one rig year or less, but that landscape has since eroded and has left the market more dependent on the glacial spending habits of the major deepwater operators, which were 72% of the floater expenditures in 2014.

Figure 142: Customer landscape for floating rigs shrank



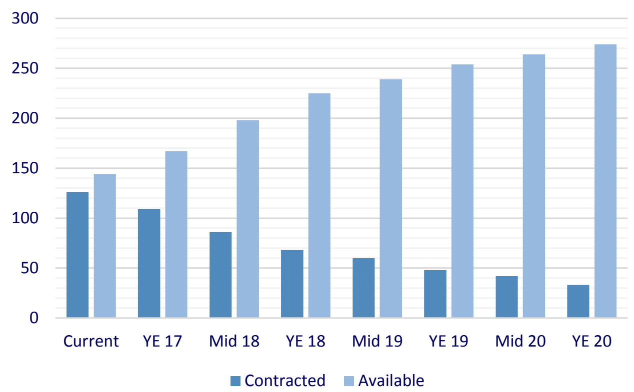
Source: ODS-Petrodata, Deutsche Bank

Figure 143: Revenues in backlog for the top floating rig customers

	Floating rig expenditures ($m)					
Operator	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Petrobras	8,272	7,083	5,090	4,372	3,931	3,434
Statoil	2,873	2,353	1,690	1,131	970	749
Shell	3,060	2,423	1,755	1,262	1,363	1,218
BP	2,669	2,499	2,082	1,781	1,403	1,239
Total	2,318	1,906	1,600	1,108	874	624
Chevron	1,715	1,965	1,618	940	852	598
ExxonMobil	1,579	1,703	1,006	515	90	0
Eni	1,410	1,166	1,028	737	355	156
Anadarko	1,207	1,195	988	702	489	263
ONGC	884	605	231	336	454	363
PEMEX	856	820	576	355	251	222
Apache	483	336	349	310	139	91
Hess	395	315	471	304	292	292
Sub-total	**27,721**	**24,369**	**18,484**	**13,853**	**11,462**	**9,248**
Percent of total	72%	69%	76%	79%	91%	97%
Total	**38,301**	**35,111**	**24,347**	**17,515**	**12,619**	**9,488**

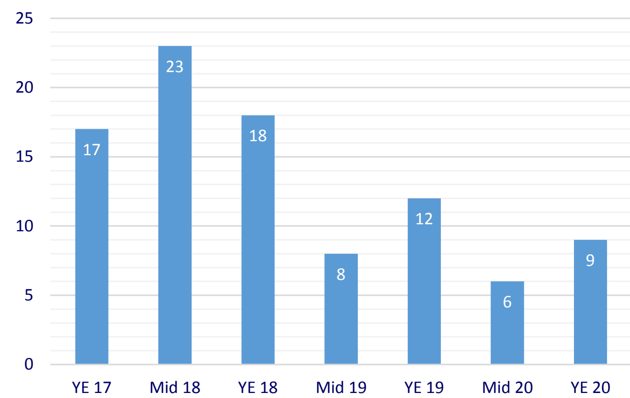
Source: ODS-Petrodata, Deutsche Bank

Figure 144: Contract expirations stacking up the idle fleet



Source: ODS-Petrodata, Deutsche Bank

Figure 145: Contract expirations

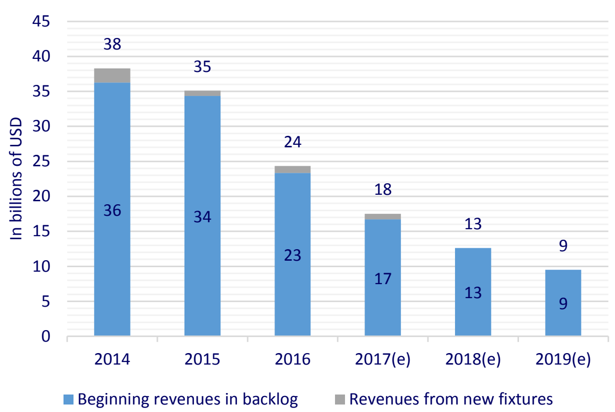


Source: ODS-Petrodata, Deutsche Bank

New tendering activity is way behind the pace of contract expirations

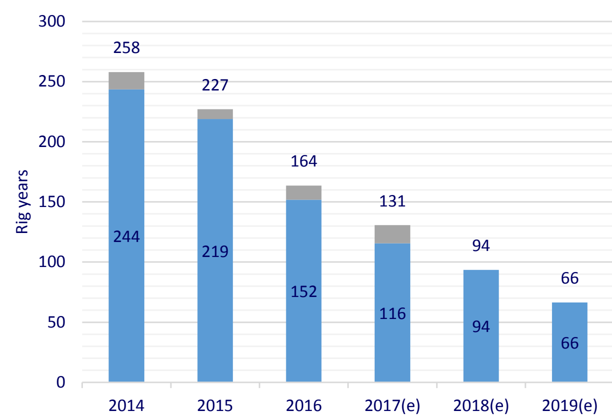
The floating rig market has only $13 billion of revenues in backlog for 2018, which is down 65% from where the industry started in 2014. Between now and year-end 2018, 22% of the floating rig fleet is facing contract expiration, which leaves only 66 rig years of backlog for 2019. That is down 73% from the 244 rig years that were in backlog at the start of 2014. Not a good starting point.

Figure 146: Revenues in backlog



Source: ODS-Petrodata, Deutsche Bank

Figure 147: Rig years in backlog

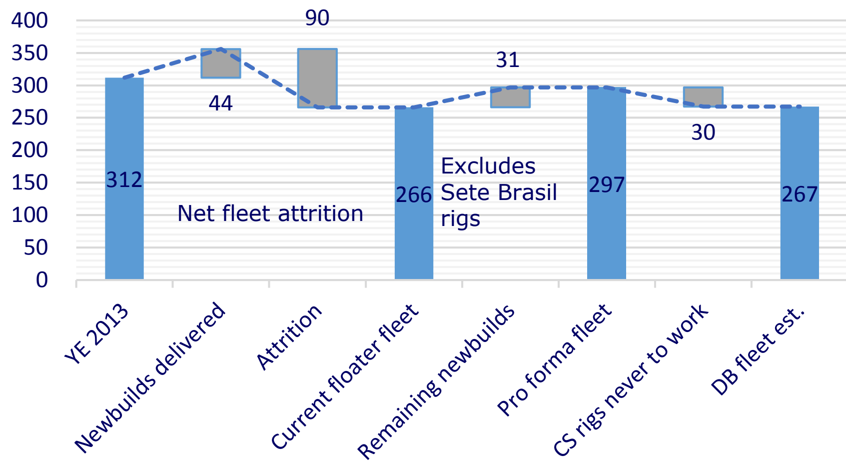


Source: ODS-Petrodata, Deutsche Bank

Record attrition to continue for several more years

The industry has officially retired a record 90 floaters since 2014, which is 42% of all the floater retirements since 1970. But the industry is still oversupplied. More floaters need to be retired, and we expect more will be retired as M&A allows companies to recharge earnings power and dispatch more of their older rigs to scrap yards. This will occur over the next several years, and will likely be contributed to by the reality that many of the industry's cold-stacked (CS) rigs are unsuitable for reactivation in today's competitive environment.

Figure 148: Market rebalancing requires more attrition



Source: ODS-Petrodata, Deutsche Bank

Many cold-stacked rigs will likely be ejected from the industry

There are 64 cold-stacked floaters, which is about 23% of the worldwide fleet. We expect at least 30 of these will never work again. It may take a few years before they are officially retired, but customers are unlikely to consider either the rig quality or the credit quality of some of these contractors. While the reactivation cost for the newer rigs is $30-50 million, the all-in cost for the 20-30 year old rigs can be as high as $100 million.

Figure 149: Cold-stacked floaters by vintage and duration stacked

	Age of rig						
Rig type	**1yr or less**	**<5 yrs**	**5+ yrs**	**10+yrs**	**20+yrs**	**30+ yrs**	**Total**
Semisubmersibles	**3**	**9**	**55**	**21**	**7**	**59**	**154**
Cold stacked	0	0	11	9	2	19	41
Duration cold stacked							
< 1 year	0	0	4	0	0	2	6
1 - 2 years	0	0	4	5	2	13	24
2 - 3 years	0	0	3	4	0	2	9
3 - 4 years	0	0	0	0	0	0	0
4 - 5 years	0	0	0	0	0	0	0
5+ years	0	0	0	0	0	2	2
Total	**0**	**0**	**11**	**9**	**2**	**19**	**41**
Drillships	**1**	**46**	**47**	**13**	**0**	**12**	**119**
Cold stacked	0	3	7	11	0	2	23
Duration cold stacked							
< 1 year	0	1	2	0	0	0	3
1 - 2 years	0	2	5	3	0	1	11
2 - 3 years	0	0	0	8	0	1	9
3 - 4 years	0	0	0	0	0	0	0
4 - 5 years	0	0	0	0	0	0	0
5+ years	0	0	0	0	0	0	0
Total	**0**	**3**	**7**	**11**	**0**	**2**	**23**

Source: ODS-Petrodata, Deutsche Bank

Figure 150: Floater attrition by contractor

Floaters	2014	2015	2016	2017	Total
Transocean	11	11	8	9	**39**
Diamond Offshore	3	7	3	5	**18**
Ensco	0	2	6	0	**8**
Noble	0	4	0	2	**6**
Atwood	1	1	1	1	**4**
Paragon Offshore	0	2	0	1	**3**
Saipem	0	1	1	1	**3**
Albatross Energy	0	1	0	0	**1**
Other	0	1	5	2	**8**
Total	**15**	**30**	**24**	**21**	**90**

Source: ODS-Petrodata, Deutsche Bank

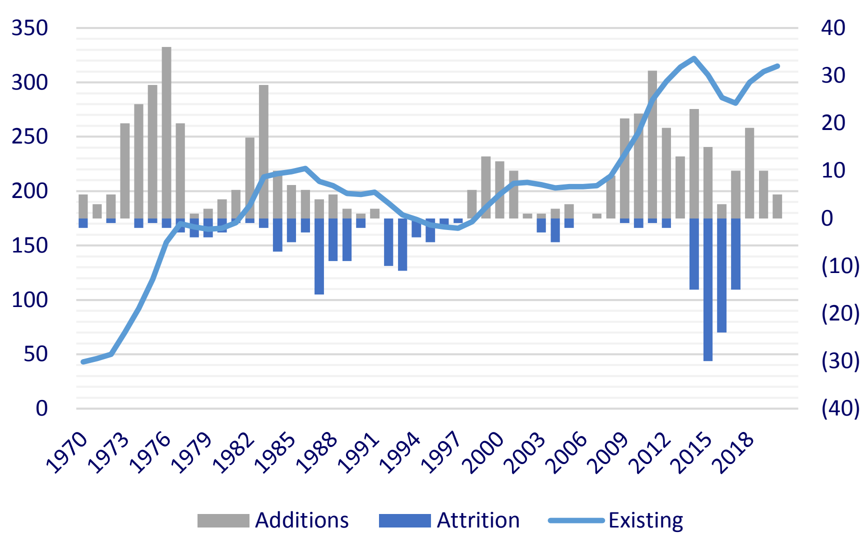
Transocean and Diamond Offshore lead the scrapping effort

Transocean and Diamond Offshore have retired a combined 57 rigs out of the total 90 since 2014. While owning less than 50% of the worldwide fleet, US drillers in total have been responsible for over 80% of the retirements. About 40% of the 30+ year old cold-stacked floaters are owned by small contractors that have little else in terms of revenues, thus may not be proactively retiring rigs, but these are the rigs being retired by the customers.

There are still 31 newbuild floaters in the queue

Since 2005, the industry has ordered 200 newbuild floaters with 31 still in the queue for delivery, excluding the Sete Brasil rigs. Only ten of the remaining 38 have commitments. The industry has successfully deferred the vast majority of these deliveries and as of now has 19 deliveries in 2018 and ten in 2019.

Figure 151: Floating fleet trends

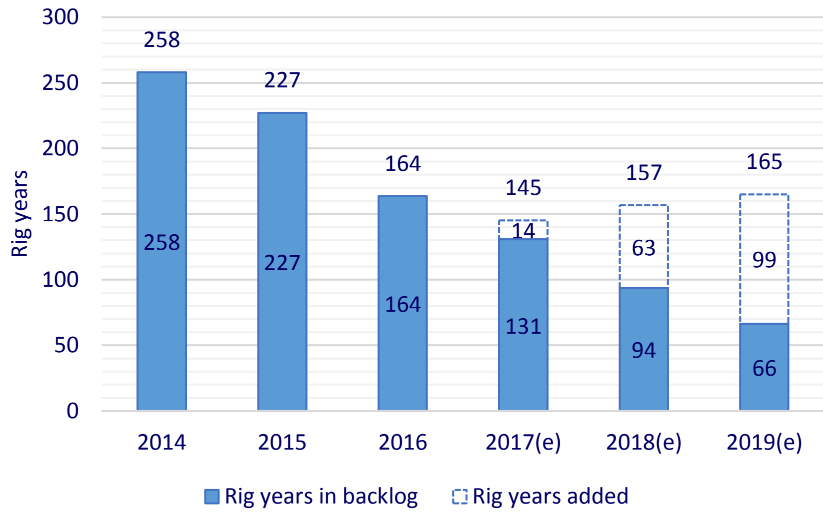


Source: ODS-Petrodata, Deutsche Bank

Floater market bottoming, but we expect a slow laborious recovery

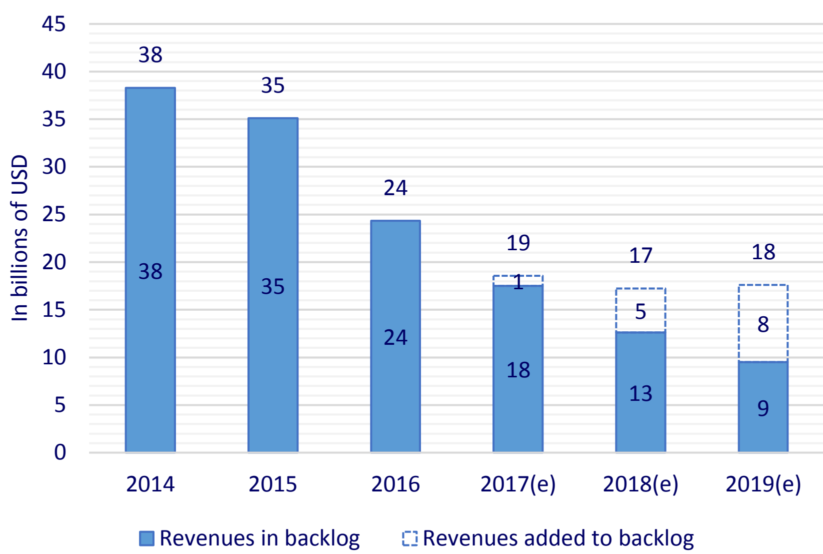
We believe the bottom is in, but the recovery will be slow and riddled with fierce pricing tactics. Leading edge dayrates have plunged to the $170,000 per day level from over $650,000 because utilization is top of mind for contractors. We expect demand will have bottomed at about 145 rig years in 2017 versus 258 in 2014. But we only model in a recovery to 165 rig years by 2019. In terms of industry revenues, we expect them to be below 2017 levels due to the plunge in dayrates.

Figure 152: Slow floating rig recovery through 2019



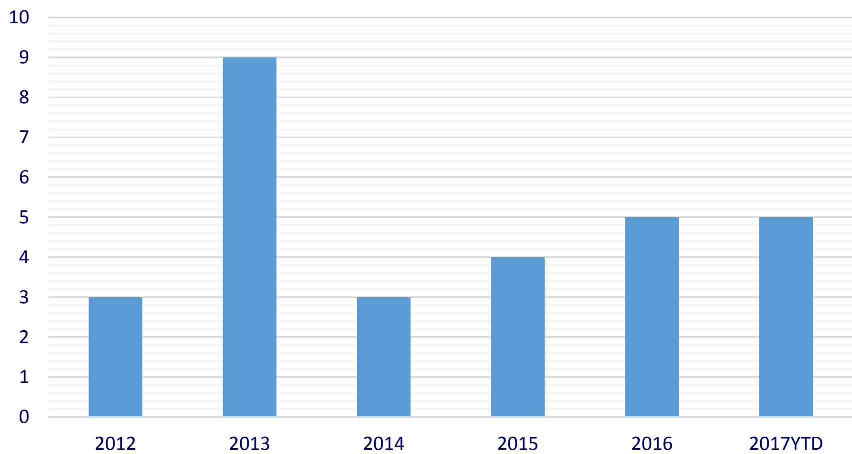
Source: ODS-Petrodata, Deutsche Bank

Figure 153: Strong pricing tactics will be a drag on backlog revenues



Source: ODS-Petrodata, Deutsche Bank

Figure 154: Deepwater FIDs YTD in-line with full year 2016 level



Source: Deutsche Bank

Lower costs, technology and best practices keep deepwater viable

The urgency in the deepwater through 2014 as rig availability was tight and dayrates had surged to $650,000 per day fueled a bloated cost structure and forced errors that now have the chance to be remedied. The focus is now on more cost efficient facilities using modularization, miniaturization, advanced materials, and more efficient processes to reduce costs. Cost cuts have actually come to fruition faster than many in the industry had expected with many of the incremental deepwater opportunities now involving brownfield tie-backs in the large infrastructure centers in the Gulf of Mexico and North Sea. Statoil for example, which ranked second in terms early contract terminations, has achieved 20-30% cost improvements in drilling and completions as well as facilities and field costs in 2/3rd the expected time frame. Breakeven prices industry-wide have come down below $50, and for some brownfield projects, below $40. Some large projects are already economic.

Jackups finding a bottom

Exposure to the jackup market has faded over the years as contractors including Transocean, Noble and Diamond have repositioned their fleets to focus on the ultra-deepwater. Transocean recently sold its high-specification jackup fleet to Borr Drilling and is now 100% floaters. Transocean used to be the largest jackup operator following the acquisition of GlobalSantaFe.

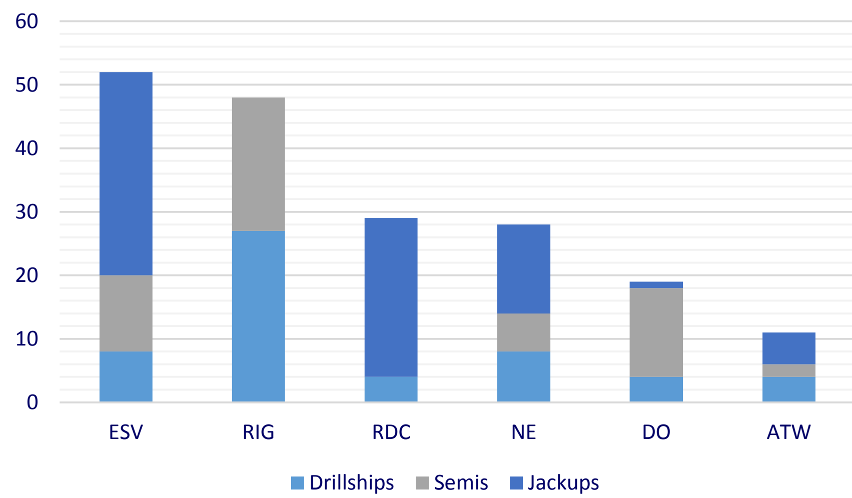
The jackup market is highly fragmented with 127 drilling contractors. But the rigs are old. About 49% of the 539 active worldwide jackups are 30+ years old. This is the competitive edge Rowan has over the industry. There are roughly 70 high-specification jackups with hook loads of 2 million lbs. or more, and Rowan has 19 of them. While most of the 30+ year old rigs will enjoy sporadic at best utilization with very little pricing, Rowan's fleet of high-specification jackups provides it with a superior competitive positioning to be among the first to gain backlog and pricing as the industry slowly recovers.

Figure 155: Cold-stacked jackups by vintage and duration stacked

Rig type	Age of rig						
	1yr or less	<5 yrs	5+ yrs	10+yrs	20+yrs	30+ yrs	Total
Jackups	**11**	**106**	**97**	**47**	**15**	**263**	**539**
Cold stacked	0	0	4	4	4	61	73
Duration cold stacked							
< 1 year	0	0	1	1	2	1	5
1 - 2 years	0	0	1	0	1	8	10
2 - 3 years	0	0	0	3	1	30	34
3 - 4 years	0	0	2	0	0	9	11
4 - 5 years	0	0	0	0	0	1	1
5+ years	0	0	0	0	0	12	12
Total	**0**	**0**	**4**	**4**	**4**	**61**	**73**

Source: ODS-Petrodata, Deutsche Bank

Figure 156: Fleet distributions



Source: ODS-Petrodata, Deutsche Bank

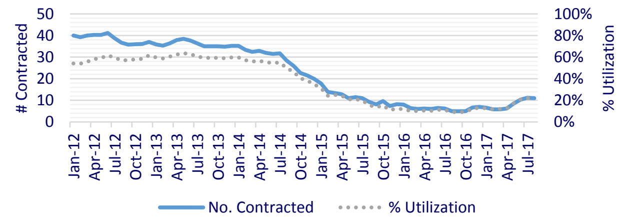
Figure 157: Offshore fleet age distribution

Rig type	Fleet age								
	1yr or less	<5 yrs	5+ yrs	10+yrs	20+yrs	30+ yrs	Constr.	Total	Avg age
Jackup	11	106	97	47	15	263	97	**636**	22.1
Semisubmersible	3	9	55	21	7	59	13	**167**	20.4
Drillship	1	46	47	13	0	12	25	**144**	9.7
Jackup	2%	17%	15%	7%	2%	41%	15%		
Semisubmersible	2%	5%	33%	13%	4%	35%	8%		
Drillship	1%	32%	33%	9%	0%	8%	17%		

Source: ODS-Petrodata, Deutsche Bank

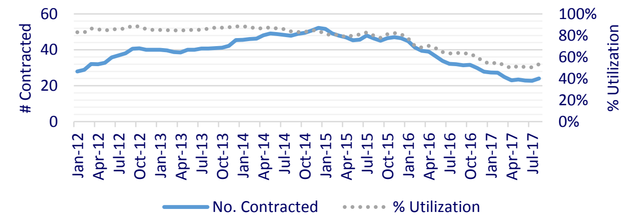
Gulf of Mexico

Figure 158: Jackups contracted vs utilization



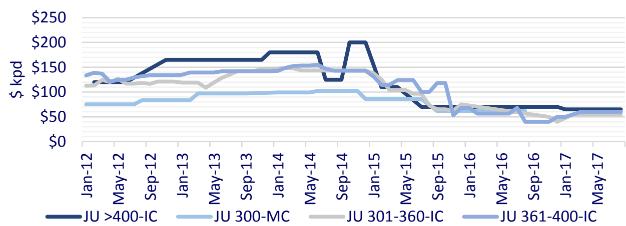
Source: ODS-Petrodata

Figure 159: Floaters contracted vs utilization



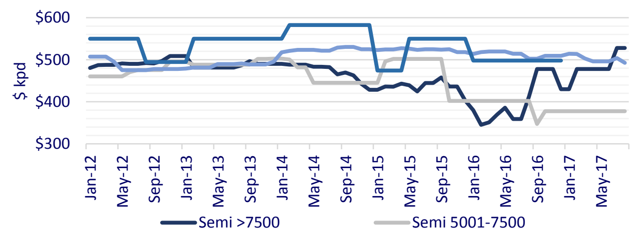
Source: ODS-Petrodata

Figure 160: Jackup dayrates



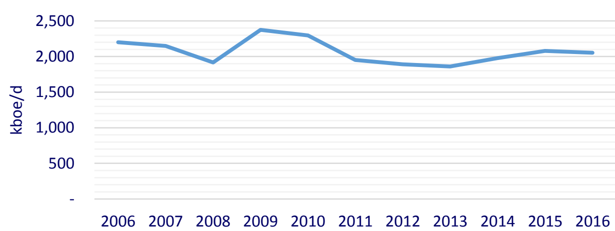
Source: ODS-Petrodata

Figure 161: Floater dayrates



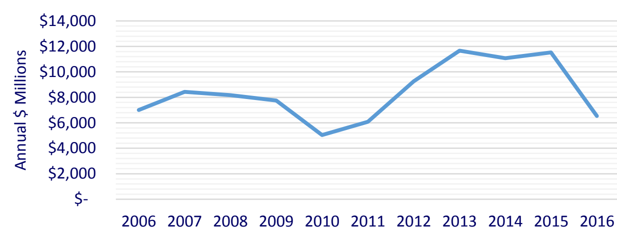
Source: ODS-Petrodata

Figure 162: Offshore production



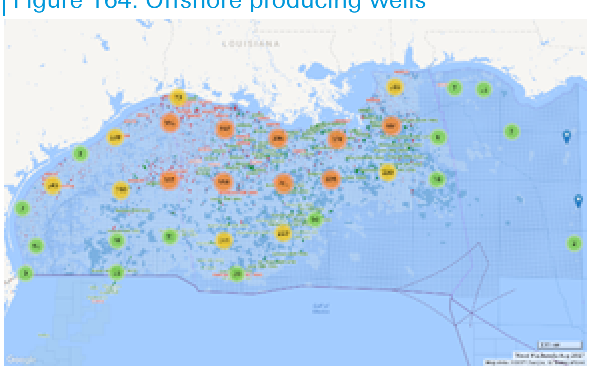
Source: Wood Mackenzie

Figure 163: Capital Expenditures



Source: Wood Mackenzie

Figure 164: Offshore producing wells



Source: Wood Mackenzie

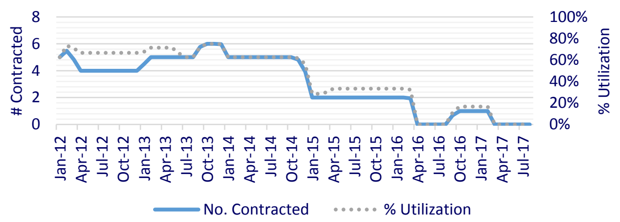
Figure 165: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	Transocean	7	Shell	4
#2	Seadrill	4	Chevron	4
#3	Diamond Offshore	4	Anadarko	3
#4	Noble	4	Hess	3
#5	Ensco	1	BP	3

Source: ODS-Petrodata

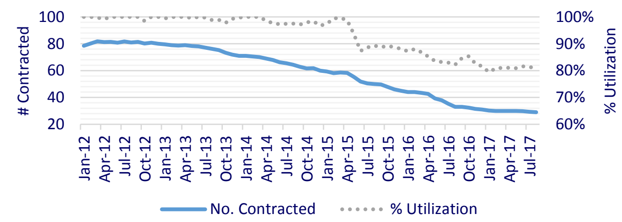
Brazil

Figure 166: Jackups contracted vs utilization



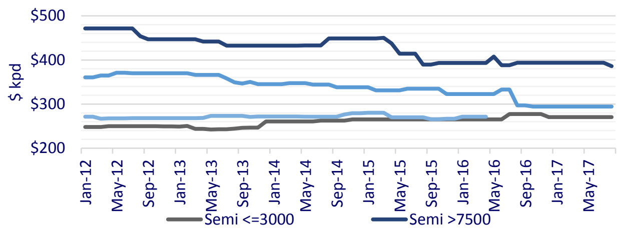
Source: ODS-Petrodata

Figure 167: Floaters contracted vs utilization



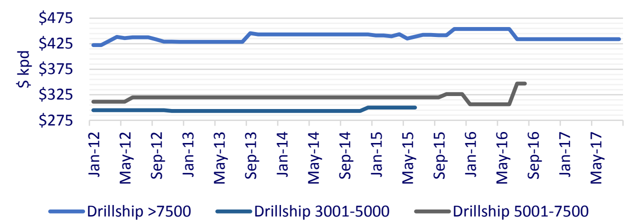
Source: ODS-Petrodata

Figure 168: Jackup dayrates



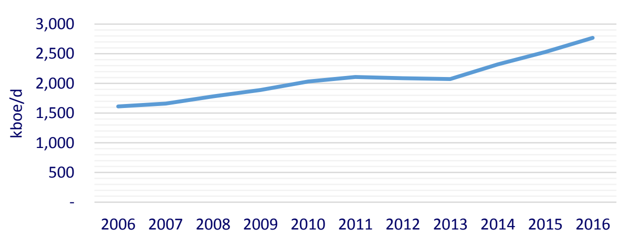
Source: ODS-Petrodata

Figure 169: Floater dayrates



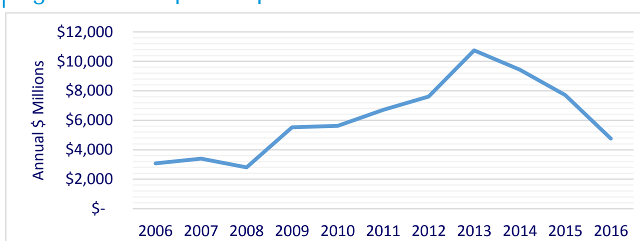
Source: ODS-Petrodata

Figure 170: Offshore production



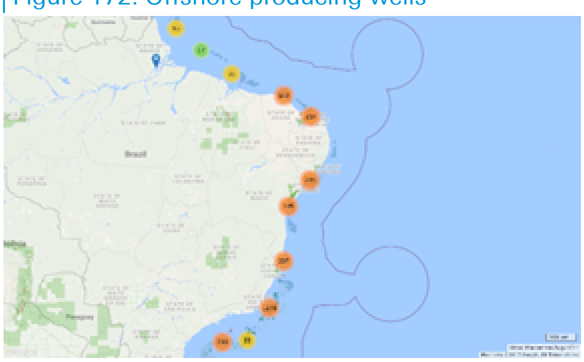
Source: Wood Mackenzie

Figure 171: Capital Expenditures



Source: Wood Mackenzie

Figure 172: Offshore producing wells



Source: Wood Mackenzie

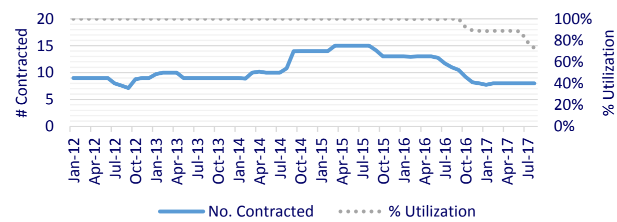
Figure 173: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	QGOG Constellation	6	Petrobras	27
#2	Odebrecht	6		
#3	Seadrill	3		
#4	Transocean	2		
#5	Ensco	2		

Source: ODS-Petrodata

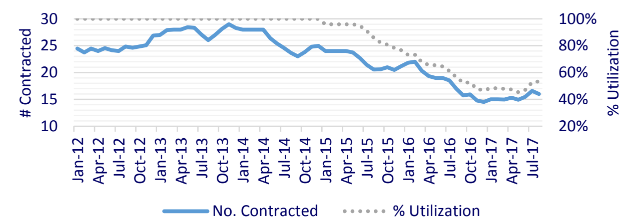
Norway

Figure 174: Jackups contracted vs utilization



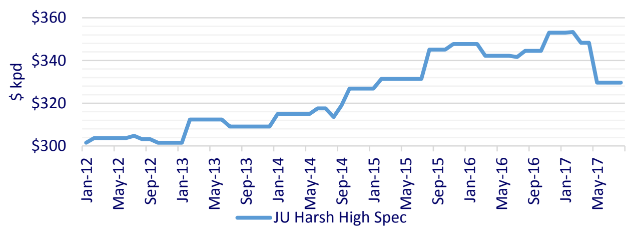
Source: ODS-Petrodata

Figure 175: Floaters contracted vs utilization



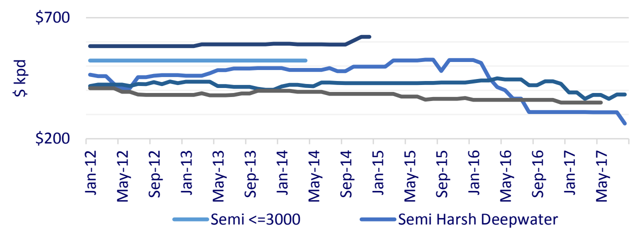
Source: ODS-Petrodata

Figure 176: Jackup dayrates



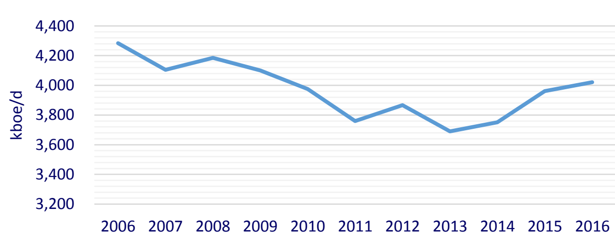
Source: ODS-Petrodata

Figure 177: Floater dayrates



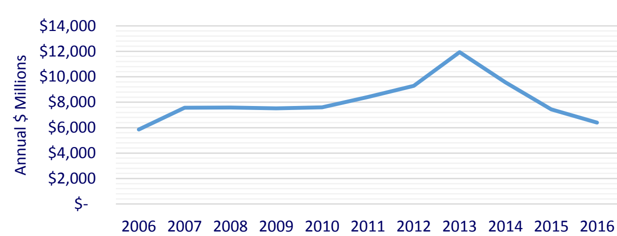
Source: ODS-Petrodata

Figure 178: Offshore production



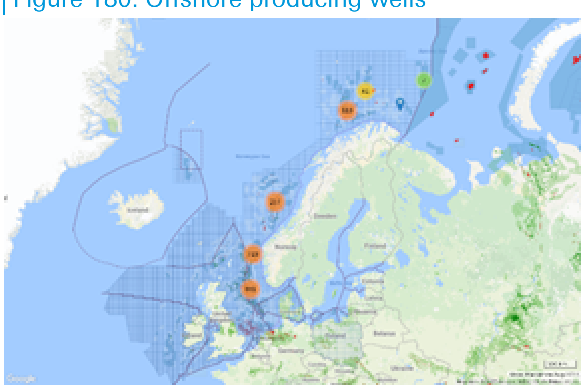
Source: Wood Mackenzie

Figure 179: Capital expenditures



Source: Wood Mackenzie

Figure 180: Offshore producing wells



Source: Wood Mackenzie

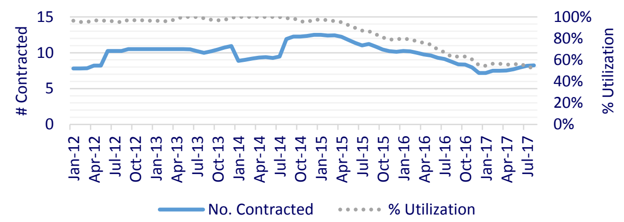
Figure 181: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	Songa Offshore	4	Statoil	8
#2	Odfjell Drilling	3	Aker BP	1
#3	Dolphin	1	Wintershall	1
#4	Ocean Rig	1	Eni	1
#5	Transocean	1	Lundin Petroleum	1

Source: ODS-Petrodata

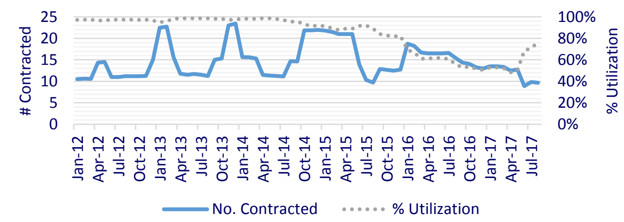
North Sea

Figure 182: Jackups contracted vs utilization



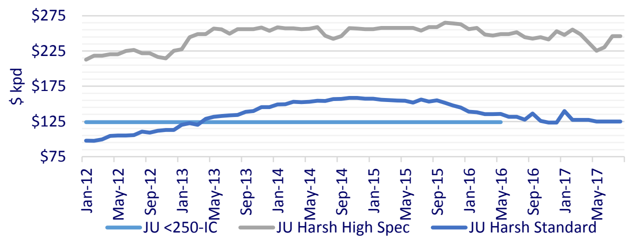
Source: ODS-Petrodata

Figure 183: Floaters contracted vs utilization



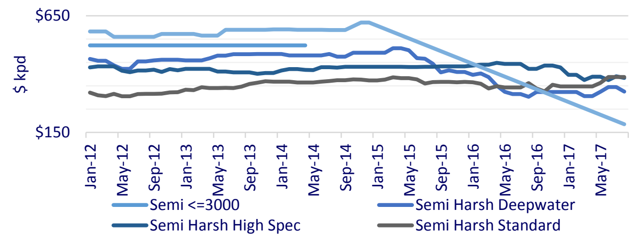
Source: ODS-Petrodata

Figure 184: Jackup dayrates



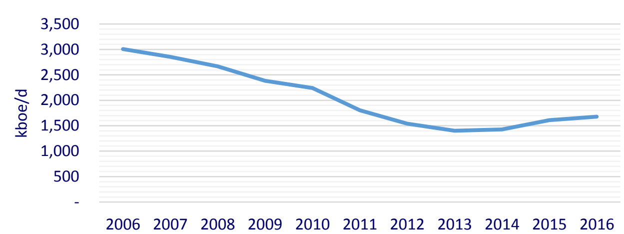
Source: ODS-Petrodata

Figure 185: Floater dayrates



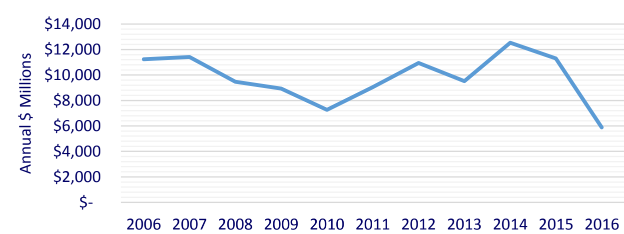
Source: ODS-Petrodata

Figure 186: Offshore production



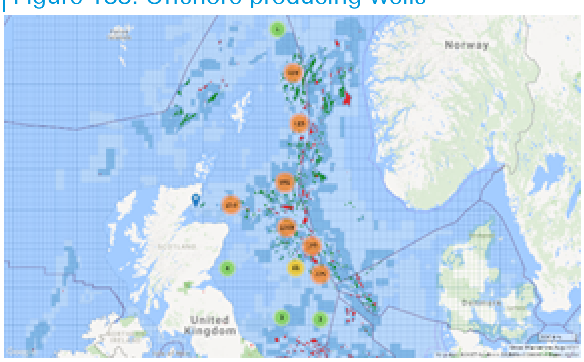
Source: Wood Mackenzie

Figure 187: Capital expenditures



Source: Wood Mackenzie

Figure 188: Offshore producing wells



Source: Wood Mackenzie

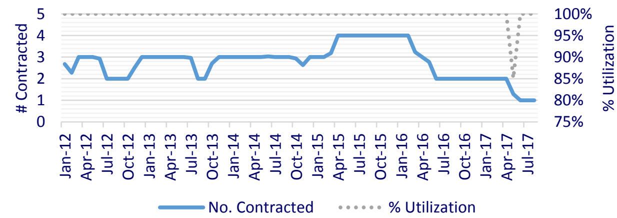
Figure 189: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	Transocean	5	Statoil	9
#2	Songa Offshore	4	BP	2
#3	Odfjell Drilling	4	Providence	1
#4	Diamond Offshore	3	Aker BP	1
#5	Paragon Offshore	1	Apache	1

Source: ODS-Petrodata

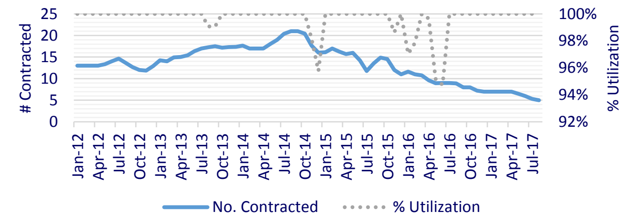
Angola

Figure 190: Jackups contracted vs utilization



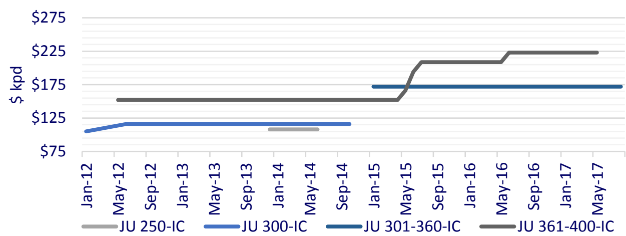
Source: ODS-Petrodata

Figure 191: Floaters contracted vs utilization



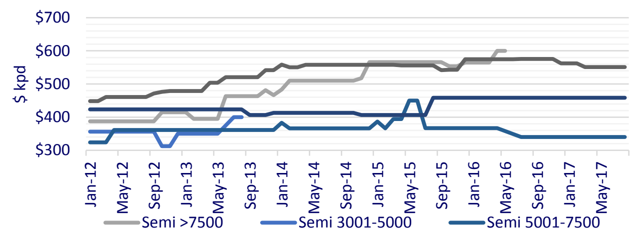
Source: ODS-Petrodata

Figure 192: Jackup dayrates



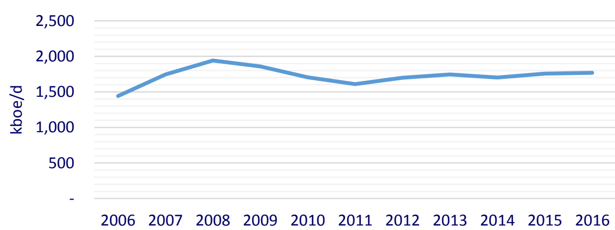
Source: ODS-Petrodata

Figure 193: Floater dayrates



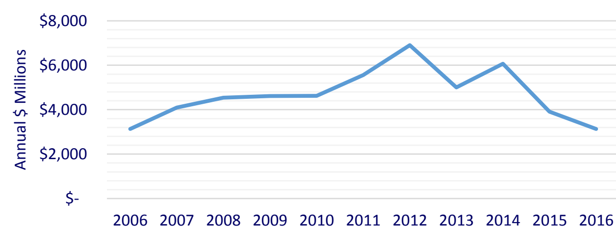
Source: ODS-Petrodata

Figure 194: Offshore production



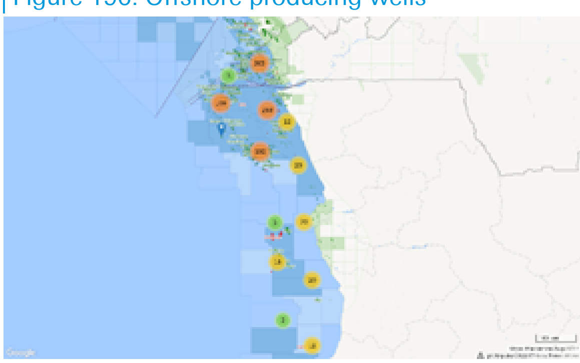
Source: Wood Mackenzie

Figure 195: Capital expenditures



Source: Wood Mackenzie

Figure 196: Offshore producing wells



Source: Wood Mackenzie

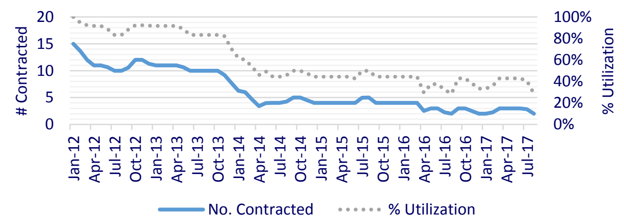
Figure 197: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	Seadrill	2	Total	3
#2	Ocean Rig	2	Eni	1
#3	Ensco	1	ExxonMobil	1
#4				
#5				

Source: ODS-Petrodata

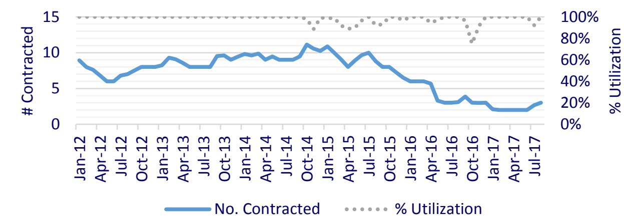
Nigeria

Figure 198: Jackups contracted vs utilization



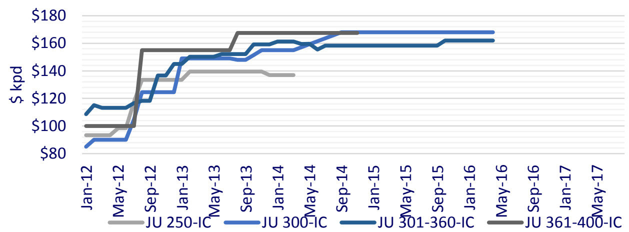
Source: ODS-Petrodata

Figure 199: Floaters contracted vs utilization



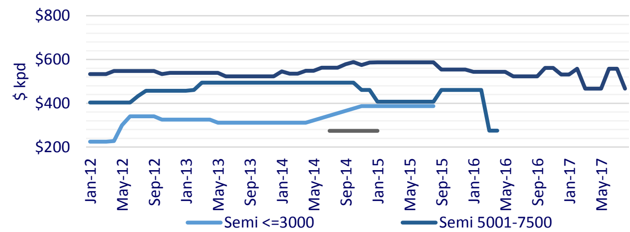
Source: ODS-Petrodata

Figure 200: Jackup dayrates



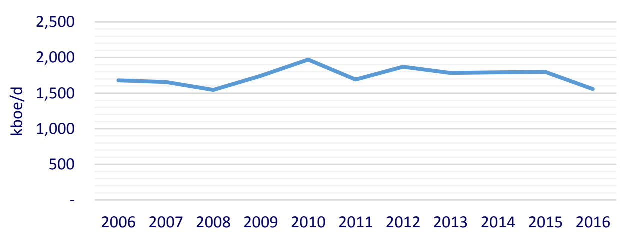
Source: ODS-Petrodata

Figure 201: Floater dayrates



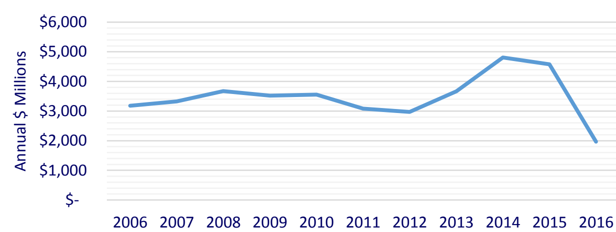
Source: ODS-Petrodata

Figure 202: Offshore production



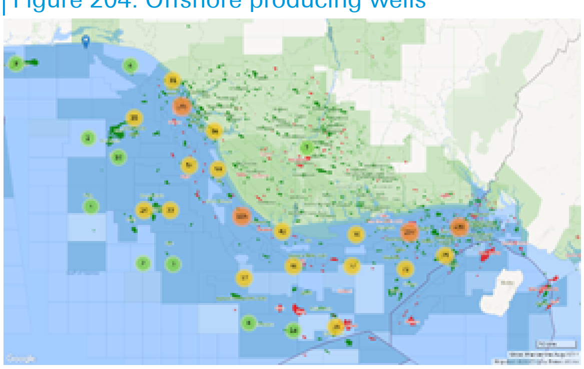
Source: Wood Mackenzie

Figure 203: Capital expenditures



Source: Wood Mackenzie

Figure 204: Offshore producing wells



Source: Wood Mackenzie

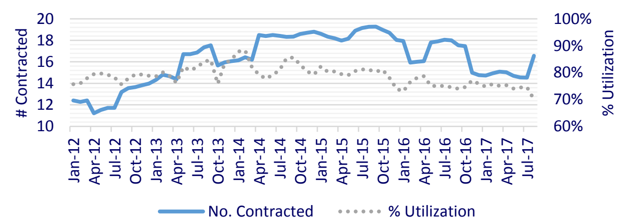
Figure 205: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	Seadrill	1	Total	1
#2	Pacific Drilling	1	Erin Energy	1
#3				
#4				
#5				

Source: ODS-Petrodata

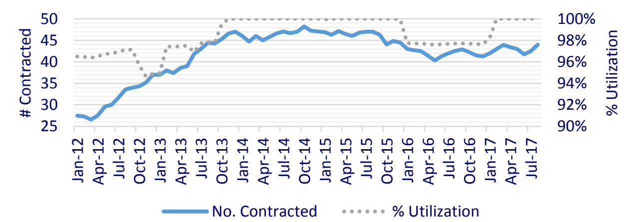
Middle East & Saudi Arabia

Figure 206: Middle East jackups



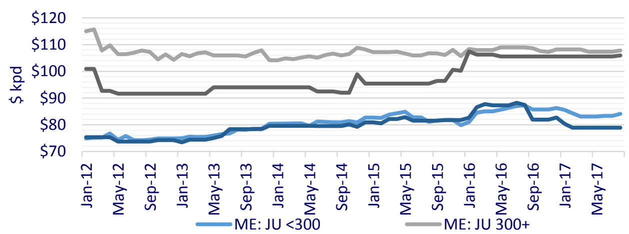
Source: ODS-Petrodata

Figure 207: Saudi Arabia jackups



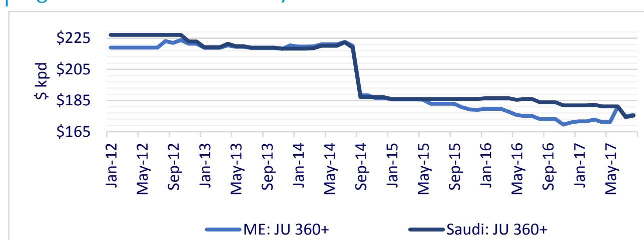
Source: ODS-Petrodata

Figure 208: JU <300, 300+ dayrates



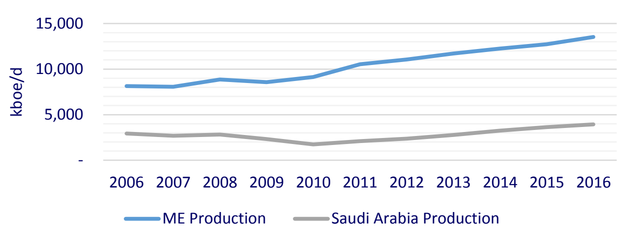
Source: ODS-Petrodata

Figure 209: JU 360+ dayrates



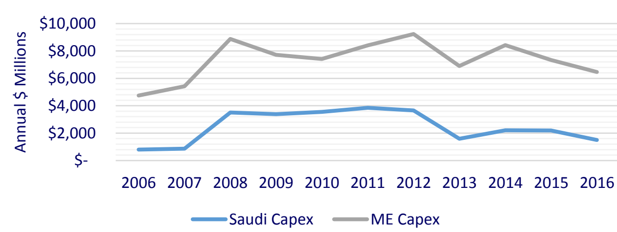
Source: ODS-Petrodata

Figure 210: ME vs Saudi Arabia offshore production



Source: Wood Mackenzie

Figure 211: ME vs Saudi Arabia capital expenditures



Source: Wood Mackenzie

Figure 212: Offshore producing wells

Source: Wood Mackenzie

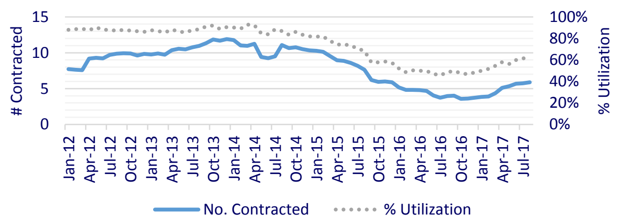
Figure 213: Top contractors and operators

		Manager	# Rigs	Operator	# Rigs
Middle East	#1	National Drilling	20	Saudi Aramco	45
	#2	Shelf Drilling	12	Adma-Opco	18
	#3	Rowan	10	IOOC	6
	#4	Gulf Drilling Int'l	9	Pars Oil & Gas	5
	#5	Noble	7	Operator TBA	5
		Manager	**# Rigs**	**Operator**	**# Rigs**
Saudi Arabia	#1	Rowan	10	Saudi Aramco	44
	#2	Shelf Drilling	6		
	#3	Ensco	6		
	#4	Seadrill	4		
	#5	Noble	4		

Source: ODS-Petrodata

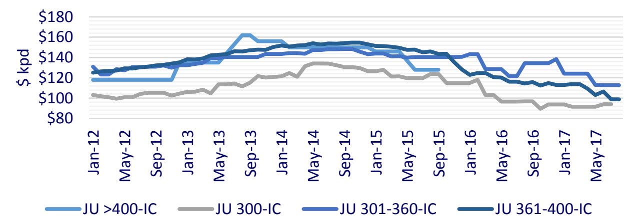
Asia Pacific

Figure 214: Jackups contracted vs utilization



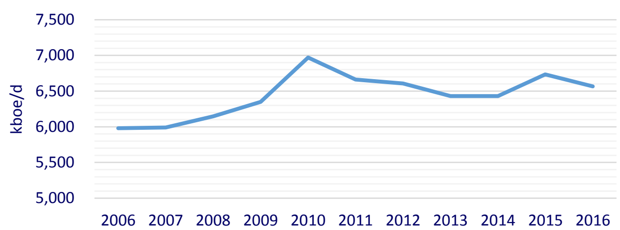
Source: ODS-Petrodata

Figure 215: Jackup dayrates



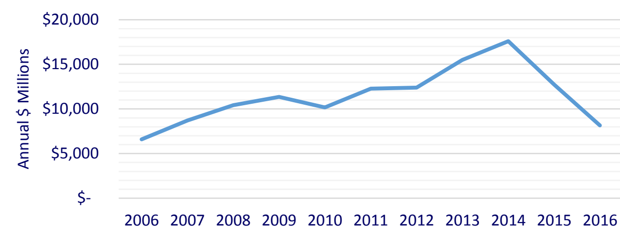
Source: ODS-Petrodata

Figure 216: Offshore production



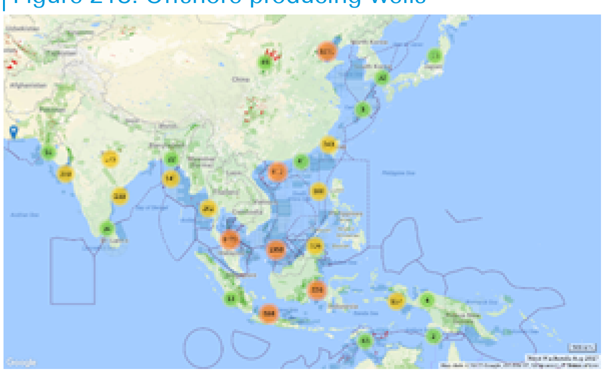
Source: Wood Mackenzie

Figure 217: Capital expenditures



Source: Wood Mackenzie

Figure 218: Offshore producing wells



Source: Wood Mackenzie

Figure 219: Top contractors and operators

	Manager	# Rigs	Operator	# Rigs
#1	UMW Offshore Drilling	6	Vietsovpetro	9
#2	Vietsovpetro	5	Petronas Carigali	5
#3	PV Drilling	4	Chevron	4
#4	Shelf Drilling	2	Pertamina	2
#5	Seadrill	2	Saka Energi Indonesia	1

Source: ODS-Petrodata

FIDs are slowly picking up

Large upstream projects, both offshore and onshore, are usually delivered by a group of energy companies rather than a single large owner. This helps to spread out project risks, improve project financing for these large, multi-year projects, and knowledge sharing amongst the players in the industry. In order for a project to reach FID (Final Investment Decision) several steps have to be taken including Front End Engineering Design (FEED) studies, country concessions, building the necessary production facilities, order some long lead time items, just to name a few. The industry tracks FIDs closely because once the decision is made usually major contract tenders are awarded in the following months.

Figure 220: Production outlook for major project FIDs (kboe/d)

(kboe/d)	2017	2018	2019	2020	2021	2022	2023	2024	2025
Africa	29	29	67	100	184	618	1,196	1,682	1,900
Latin America	15	30	22	144	394	604	914	1,312	1,770
Middle East	49	229	367	624	1,290	1,991	2,311	2,433	2,605
Asia	234	318	399	568	816	1,163	1,357	1,674	2,038
Europe	0	10	39	446	619	1,022	1,292	1,418	1,453
North America	10	25	35	35	67	319	676	805	836
Total	337	640	929	1,918	3,370	5,717	7,745	9,325	10,601

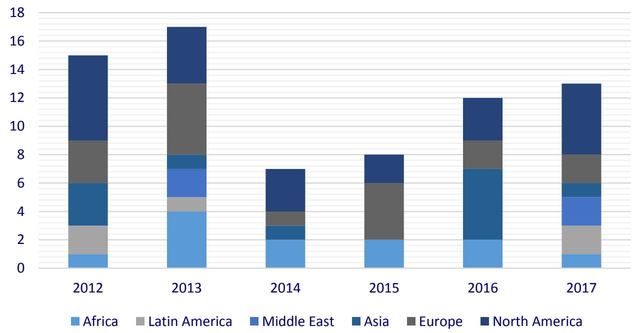
Source: Wood Mackenzie, Deutsche Bank

The energy downturn and the subsequent lower for longer oil price environment has encouraged operators to focus more on shorter-cycle projects in their portfolio. There has been very little FIDs being announced the past few years as projects were delayed in order to get re-designed to reflect the new environment. There are still meaningful challenges to the deepwater development including geologic risk, project execution risk, and locking up capital in a long project timeline.

The industry has shown in the past it can meaningfully improve project economics and has responded the same way to this challenge by working together to make offshore viable again as they remove costs out of the project work. The industry is pursuing multiples avenues of standardization, such as lowering the delivery time from manufacturers from 26 months to 14-16 months for orders that are customized and pushing standardized engineering solutions rather than always re-inventing processes for similar field designs.

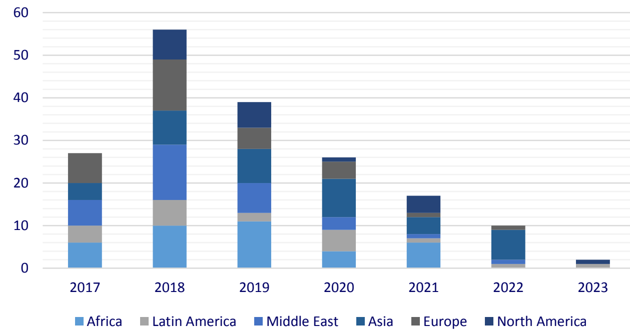
Right now sanctions are mainly focused on brownfield development and subsea tiebacks which have less exploration risk and faster timeline to first production. However, XOM did announce in June that it has made FID on the first phase of development for the Liza field. Phase 1 development includes a subsea production system and FPSO vessel designed to produce 120,000 barrels of oil per day. Production is expected to begin by 2020, less than five years after the field was discovered. Conversely, only 7 exploration wells have been drilling in Brazil in 2017 compared to over 200 exploration wells back in 2012.

Figure 221: Sanctioned projects by region



Source: Wood Mackenzie

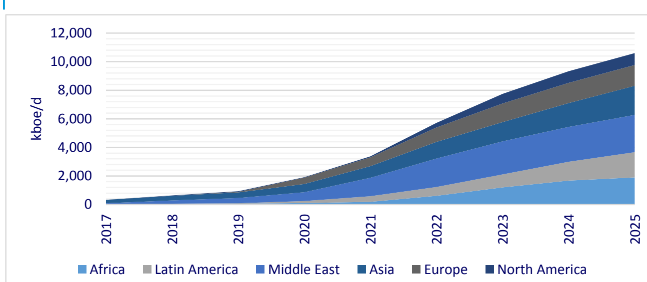
Figure 222: Future FIDs



Source: Wood Mackenzie

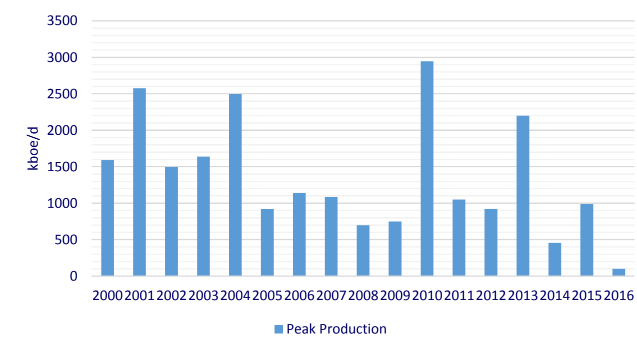
Wood Mackenzie tracks future FID projects which currently has over 180 potential projects that could reach FID by 2025. This list does not include US unconventional plays and fields with commercial reserves smaller than 50 mmboe. Interesting to note in the above graphs, the composition of FIDs from the ones that have been sanctioned in the past six years to the future projects being tracked changes. North America and Europe were the leading regions for sanctioned projects in the past six years while Asia and Africa look to be leading regions for future FID projects. Russia accounts for almost one-third to the total projects in Asia.

Figure 223: Future FID expected liquids production



Source: Wood Mackenzie

Figure 224: Peak production from FIDs by Year of Sanction



Source: Wood Mackenzie

Wood Mackenzie models out potential production by field if all of the potential projects make it to FID. Given the time to first production, onshore and brownfield projects have the quickest time to first production followed by larger deepwater projects. Total production from the projects that are being tracked starts at only 337 kboe/d in 2017 while ramping to 5,717 kboe/d in 2022 and 10,601 kboe/d in 2025.

The impact of the downturn and recent focus on faster cycle times can be seen when looking at the graph showing peak production from FIDs by year of sanction. Project deferrals and a lack of FID announced during the downturn will start to have a greater impact on incremental deepwater production. While 2017 finally makes a turnaround with major projects being sanctioned, including some greenfield, the average production start-up year based on the list of projects that are being tracked is around 2021/ 2022.

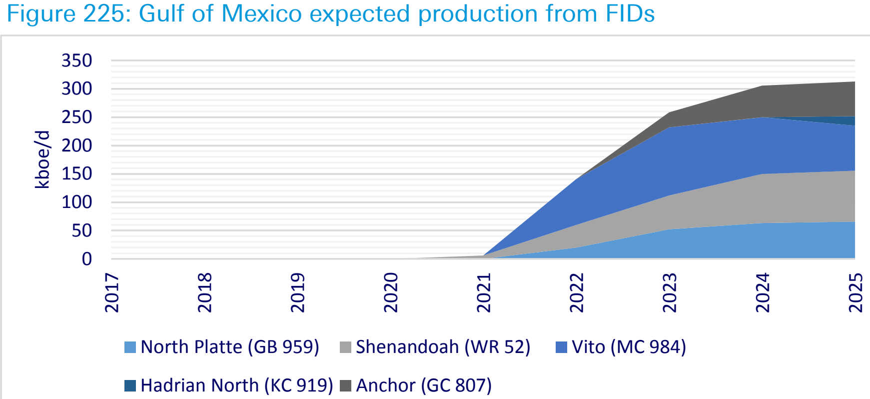
Gulf of Mexico

The deepwater Gulf of Mexico still accounts for approximately 15% of US crude oil production. While the rig count remains at low levels and the industry cost structure is still working its way lower, it is still an important part of the US supply picture. Wood Mackenzie estimates that liquids production in 2017 will average 1.39 million b/d, up from 1.22 in 2016 due to the ramp up of fields such as Delta House and Lucius with further development of Thunderhorse. They have Gulf of Mexico production hitting a new peak of 1.46 million b/d in 2019, mainly driven by Stampede, Big Foot, and Appomattox.

The downturn definitely hit activity in the Gulf of Mexico as very few projects were sanctioned in 2015-2016. Only Appomattox and Vicksburg were sanctioned in 2015 and Constellation in 2016. Evidence that the lower cost structure, improving efficiencies, and benefits from standardization and improving collaboration has already helped to see a higher level of sanction activity in 2017. Mad Dog Phase 2, Kaikias, and Buckskin have all been sanctioned so far in 2017. Wood Mackenzie estimates that Mad God Phase 2 has a breakeven below US$50/bbl Brent price, while Kaikias is around $30.

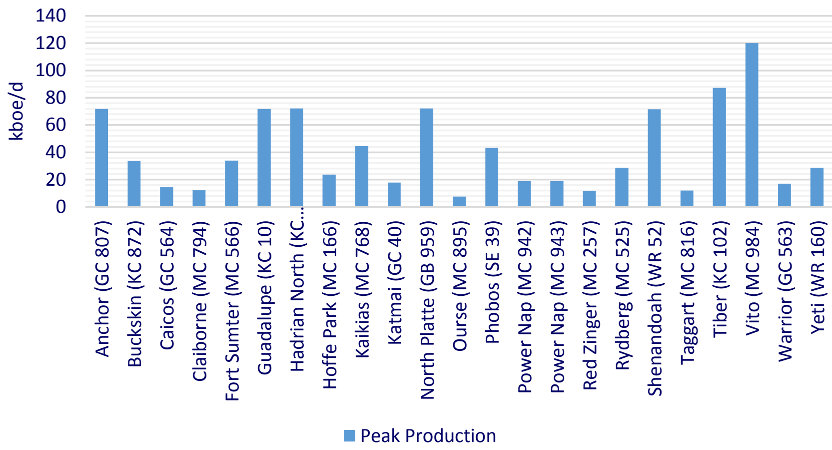
There continues to be risk that the next wave of Gulf of Mexico pre-FID projects get delayed if operators continue to focus on short-cycle investments or if operating partners' interests are not aligned. A recent example (note it is still included in the Wood Mackenzie dataset) is Shenandoah. Following dry-holes at both Shenandoah-6 and the subsequent side track, Anadarko (APC) suspended any further appraisal activity and wrote-off $900mm in dry hole and lease-hold impairment expenses associated with the project. APC will evaluate the go-forward plan by the end of November. These risks explain the difference between the two charts below as Wood Mackenzie only includes 5 pre-FID projects in its FID project tracker list. However, if we look at potential projects in the Gulf of Mexico depending on if we include discoveries that Wood Mackenzie classifies as Good Technical reserves (fields that could be economic but significant uncertainty remains over the timing of their development) then the list expands to include 23 potential projects.

Figure 225: Gulf of Mexico expected production from FIDs



Source: Wood Mackenzie

Figure 226: Potential Gulf of Mexico projects peak production



Source: Wood Mackenzie

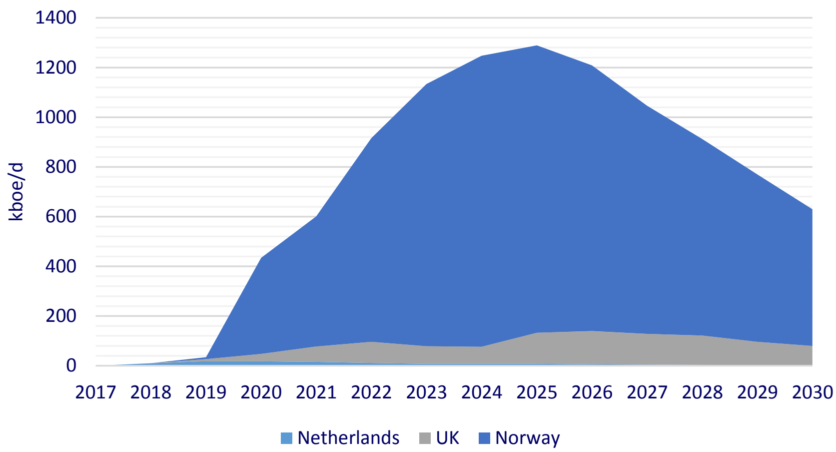
North Sea

The North Sea rig count has been steadily falling since the downturn first starting in 2014. The rig count was around the mid 40/ low 50s in the spring of that year and fell to a low in the high teens in October 2016. Since then it has remained mostly in the mid-20s level. The North Sea has also seen quite a bit of M&A this year with 12 deals announced as private equity increased their exposure to the region while majors divested some assets. Wood Mackenzie has tracked seven fields that came online in the first half of the year with eight more expected in the second half. But FIDs in 2017 have been off to a slow start with three sanctioned so far, all focused on Norway, and mostly brownfield and subsea tieback projects.

Wood Mackenzie expects in the second half of 2017 UK and Netherlands FIDs will be announced. These include Q/7-FA in the Netherlands, Lancaster in the UK, and YME Phase III, Snadd, and the Snorre Expansion in Norway. While both sides of the North Sea are picking up, the Norwegian side has the larger projects by reserve size. Most of the projects on the Norwegian side are being run by larger operators like Statoil, Repsol, and Aker BP.

While not quite considered an FID, but this example does illustrate the impact both cost reductions and project standardization are having looking at the Njord future project in Norway. The Njord future project will repair a platform and upgrade drilling facilities, with production expected to re-start in 2020 with in-fill drilling resumes in the field. Wood Mackenzie estimates that the capex/boe in the Njord future project has fallen around 30% since 3Q14.

Figure 227: North Sea expected FID production



Source: Wood Mackenzie

Top 20 Projects by Largest Commercial Reserves

Below is the list of top 20 projects by largest commercial reserves. The list of projects is mostly greenfield (15), but more of a mix between offshore/ shelf/ LNG (13) and onshore (7) than one might expect. The largest onshore projects are found in Russia and the Middle East. The largest LNG projects are in Africa. While Latin America only shows up twice in the top 20 list, there is no project in North America as Wood Mackenzie's project list is only tracking mostly brownfield oil sands expansions and the 5 expected FID projects shown above in the Gulf of Mexico section.

Figure 228: Top 20 projects by largest commercial reserves

Project	Region	Country	Operator	Project Type	Type	Expected FID	Production Start Up Yr	Peak Prod Yr	Commercial Reserves (mmboe)
Kharasaveiskoye	Asia	Russia	Gazprom	Conventional Onshore	Greenfield	Jan-20	Jan-23	2033	6,451
Libra	LatAm	Brazil	Petrobras	Deepwater	Greenfield	Jul-17	Jul-21	2030	5,684
Buzios (Surplus)	LatAm	Brazil	Petrobras	Deepwater	Greenfield	Jan-18	Jan-28	2028	4,862
Ob-Taz Bay Fields	Asia	Russia	Gazprom	Conventional Shelf	GreenField	Jan-20	Jan-25	2035	4,660
Kruzenshternskoye	Asia	Russia	Gazprom	Conventional Onshore	GreenField	Jan-22	Jan-27	2030	4,169
Golfinho Area	Africa	Mozambique	Anadarko	LNG	GreenField	Oct-18	Jan-23	2047	2,874
South Pars 11	Middle East	Iran	Iranian Oil	Conventional shelf	GreenField	Sep-17	Jul-20	2022	2,745
Farzad A and B	Middle East	Iran	Iranian Oil	Sour gas	GreenField	Jul-18	Jan-21	2032	2,636
Kashagan Phase Two	Asia	Kazakhstan	North Caspian	Sour gas	Brownfield	Aug-22	Jul-28	2042	2,524
Mamba Complex	Africa	Mozambique	Eni	LNG	GreenField	Jul-19	Jan-24	2048	2,477
Golshan and Ferdowsi	Middle East	Iran	Pars Oil & Gas	Conventional shelf	GreenField	Jan-25	Jan-26	2034	2,458
Majnoon Phase 3	Middle East	Iraq	Shell	Conventional onshore	Brownfield	Jan-19	Apr-20	-	2,356
Kharampurskoye	Asia	Russia	Rosneft	Conventional onshore	Brownfield	Jan-18	Oct-22	2028	2,264
Kish Phase 2 & 3 IPC	Middle East	Iran	Iranian Oil	Conventional onshore	GreenField	Aug-20	Jan-22	-	2,197
Troll Phase 3	Europe	Norway	Statoil	Conventional shelf	Brownfield	Jul-18	Jul-21	-	1,965
Iara Entorno (Surplus)	LatAm	Brazil	Petrobras	Deepwater	GreenField	Jul-20	Jan-26	2028	1,830
Block 1	Africa	Tanzania	Shell	LNG	GreenField	Jan-21	Jan-26	2032	1,761
Block 2	Africa	Tanzania	Statoil	LNG	GreenField	Jan-21	Jan-27	2032	1,761
Azadegan Phase 2	Middle East	Iran	CNPC	Conventional onshore	Brownfield	Jan-18	Jul-20	2025	1,760
Miran and Bina Bawi	Middle East	Iraq	Genel Energy	Onshore gas	GreenField	Jan-19	Jan-20	2023	1,556

Source: Wood Mackenzie

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Baker Hughes, a GE Company

Reuters	Bloomberg
BHGE.N	BHGE US

David Havens
Research Analyst
+1-212-250-3235
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Price at 5 Oct 2017 (USD)	36.48
Price target	35.00
52-week range	37.91 - 32.54

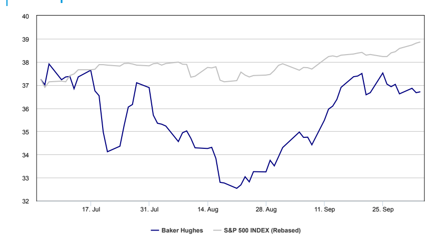
Short Cycle to Long Cycle

Initiating coverage with a Hold rating and a $35 price target
We are initiating coverage of Baker Hughes, a GE Company with a Hold rating and a $35 price target. While the company is later cycle and should generally exhibit lower cyclicality without direct exposure to pressure pumping, the varied end markets and longer lead-times add uncertainty to the earnings growth progression. We believe integration of the two companies and execution will be crucial in the early days. A lack of near term catalysts translating into near term positive earnings revisions is the basis for our Hold rating.

Strategic rationale behind the combination still remains a question
BHGE has positioned itself as a fullstream provider of equipment and services while leveraging digitalization and integrated solutions. The push for digitalization in the oil patch is not new, but there is uncertainty as to the pace of customer penetration. GE's track record in the oil patch has been mixed using acquisitions of manufacturing oriented businesses to grow. BHGE has a strong product portfolio and good innovation, but had difficulty with its delivery platform and questions remain if GE can run and support a global services model and what the new company will look like long term.

Business headwinds causes management to lower expectations
Management has already had to lower its guidance as its longer cycle businesses have been recovering slower than expected. Almost 60% of BHGE's revenue is derived from offshore, which has weighed on the business. BHGE has also faced pricing pressures in North America and a softer than expected international onshore recovery. These headwinds caused us to introduce our 2018 EBITDA estimate at $3.1bn compared to the $5.5bn in BHGE's prospectus last year.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	7.0	–	–
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	15,668.2
Shares outstanding (m)	429.5
Free float (%)	–
Volume (5 Oct 2017)	429,443
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.44	-0.04A	0.24
2Q EPS	-0.90	-0.15A	0.30
3Q EPS	-0.15	0.11	0.35
4Q EPS	-0.30	0.20	0.43
FY EPS (USD)	-1.79	0.12	1.31
OLD FY EPS (USD)	–	–	–
% Change	–	–	–
P/E (x)	–	295.7	27.9
DPS (USD)	0.68	0.68	0.68
Dividend Yield (%)	–	1.9	1.9
Revenue (USDm)	9,841.0	15,938.0	23,889.5

Source: Deutsche Bank estimates, company data

Valuation
Our $35 price target is 13.0x our 2018 EBITDA estimate of $3.1bn. The target multiple is roughly in-line with the 12.8x five-year average multiple leading up to 2014 collapse in oil prices for BHI.
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately upstream capital expenditures, 2) continued delays in longer cycle projects offshore, 3) GE starts pulling cash out of the business not allowing it to expand, 4) supporting a global services infrastructure footprint rather than just aftermarket services, and 5) an upside risk could be if BHGE is extract greater synergies from the integration process than was originally expected.

Key investment themes

Solidifying its place in the market

BHGE has positioned itself as a fullstream provider of equipment and services to drive productivity solutions to customers. The combined company's strategy is to create a differentiated solutions provider that will leverage the digital solutions and technology from GE with Baker Hughes' oilfield tools and services. Their complimentary portfolio of services and capabilities will be able to reach across the entire spectrum in the oil patch, including power generation. The goal is to leverage its breadth of the portfolio, geographic presence, technology, and digital solutions through its GE store and Predix platform. Ultimately the combined company wants to drive better efficiency for customers, create new business models, bring innovative solutions to market faster, and increase customer touch points.

The closest peer pursuing a similar strategy is likely Schlumberger (SLB) as the new BHGE is looking to provide a more integrated solution utilizing its deep portfolio of products and services. This strategy has been driven by perceived challenges in international markets as project size and complexity increases, lack of established infrastructure, customer preferences toward broader solutions to get to a simplified supply chain, and reservoirs in harsher/ more remote environments. In North America, BHGE is trying to focus on its technology leadership while offering different service models depending on customer preference.

Figure 229: Complimentary portfolio with limited overlap

GE Oil & Gas			Baker Hughes		
	% of 2015 Revenue	Top 3 Position		% of 2015 Revenue	Top 3 Position
Surface	13%		Advanced Drilling Services	24%	X
Subsea Systems & Drilling	26%	X	Logging & Evalution	6%	X
Turbomachinery Solutions	33%	X	Completion Systems	40%	X
Donstream Technology	14%		Production Optimization	22%	X
Digital Solutions	14%	X	Industrial Serviecs	8%	

Source: Company reports, Spears & Associates

Based on 2015 industry spend, the new BHGE has 60% presence in upstream markets, 30% in midstream, and 10% in downstream. We also estimate that approximately 60% of BHGE's revenue is derived from offshore while 40% is onshore based. The combined companies actually have very little overlap, so they will be able to offer solutions based complementary equipment, services, and technology across the entire oil and gas value chain. The two main product lines where they overlap are artificial lift and wireline logging, but BHGE was much larger in wireline logging than GE.

Figure 230: Limited product line overlap

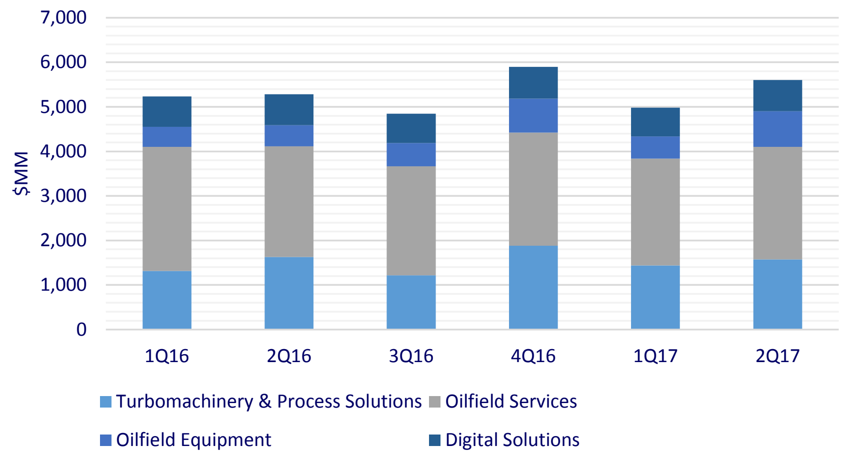
Name	Title	Prior Experience
Martin Craighead	Vice Chairman	Was Chairman & CEO of BHI since January 2012. Prior to that, he was President and COO from 2009-2012 and group President of Drilling and Evaluation from 2007-2009.
Lorenzo Simonelli	Chairman & CEO	Prior to this role, had been President and CEO of GE Transportation for the past 5 years. Also had served as CFO Americas for GE Consumer & Industrial. He joined GE financial management program in 1994.
Maria Claudia Borras	President & CEO, Oilfield Services	She is a 25 year energy veteran, 20 of which was spent at Baker Hughes. In January 2015, she moved to GE to become COO of GE Oil & Gas. At BHI she was President Latin America from 2013-2015.
Belgacem Chariag	COO	He had been President, Global Operations for BHI and Chief Integration Officer. Prior to that he was President Global Products and Services and served as President Eastern Hemisphere from 2009-2013.
Matthias Heilmann	President & CEO, Digital Solutions	20 year industry veteran, was previously Chief Digital Officer at GE Oil & Gas. Before joining GE he led ABB's global product group enterprise software business.
Derek Mathieson	CTO	Was Chief Commercial Officer for BHI since May 2016 and before that was Vice President, Chief Technology Officer from September 2015-May 2016. He joined BHI in 2008 from WellDynamics.
Brian Worrell	CFO	Was most recently CFO of GE Oil & Gas, a position he held since January 2014. Previously had worked as Vice President corporate financial planning and before that in audit. He joined GE in 1992.

Source: Company reports, Spears & Associates (Revenue in millions of USD)

Later Cycle Exposures in a Shorter Cycle World

The new BHGE's business is definitely later cycle and should generally exhibit lower cyclicality without pressure pumping. However, it has lagged peers given that the business has much lower exposure to North American completions post the spin-off of its pressure pumping business (it did retain a minority interest ownership) and likely lost some share in legacy BHGE's business lines during all of the noise the past few years. In what is likely a shorter cycle world and with commodity prices range bound, the timing for the recovery of its longer cycle businesses (subsea, drilling, LNG) remains a question. Also customer OPEX spending and related activity has been slower to recover than completion spending. International markets have lagged the recovery in North America, which typically happens, but activity has been slower to recover than many expected which provides another headwind for the business. Lastly, the company now has a backlog component to the business with some product lines geared towards larger construction projects in power generation and refining, so the market will have to get a better feel for revenue turn coming out of backlog and working capital needs.

Figure 231: BHGE orders by segment



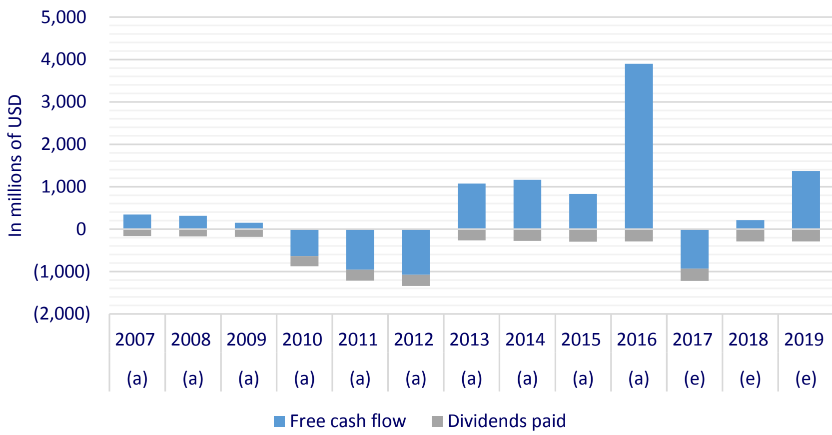
Source: Company reports

Ultimate Strategic Goals and its Capital Allocation

We would argue that many still question the strategic rationale behind the combination, but post the merger the bigger question now is what is the ultimate strategic goal for the company. One could argue that legacy BHGE had a strong product portfolio and some of the best innovation in the oil patch, but had difficulty with its delivery platform, never fully integrated BJ Services properly, and did not have enough scale and infrastructure to support global operations. GE's track record in the oil patch has been mixed at best since its entry and growth into the business mainly through acquisitions that were focused on manufacturing and leveraging its expertise in improving manufacturing efficiencies and returns.

While the business plans for the big four integrated oilfield service providers have never been so different, the market will be focused on the integration process and execution in the early days of BHGE. BHGE does have a strong balance sheet and should be able to increase leverage, questions exist around what will the capital allocation decision making process look like. Also how much will BHGE invest in the business compared to returning capital to shareholders, especially given GE's ownership in the business and its own cash needs. In other words, with GE being its largest shareholder, how much say will it have in the strategic direction and capital allocation decision making.

Figure 232: FCF vs dividends paid



Source: Company reports, Deutsche Bank (2017 forward is BHGE, 2016 prior is BHI)

Lack of near term catalysts

If we do stay in a range bound oil price environment, it has hard to see many near term catalysts for BHGE. Management has been making some solid progress on the integration processes by closing underutilized facilities, but still do not expect to see larger benefits from synergies until 2018. 3Q17 is the first quarter in which the company will report results as a single entity but it is unlikely that they will give much guidance into 2018 quite yet. Lastly, it will take some time for the market to fully understand the drivers behind the company's fundamentals.

Valuation and risks

Our $35 price target is 13.0x our 2018 EBITDA estimate of $3.1bn. The target multiple is roughly in-line with the 12.8x five-year average multiple leading up to 2014 collapse in oil prices for BHI. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately upstream capital expenditures, 2) continued delays in longer cycle projects offshore, 3) GE starts pulling cash out of the business not allowing it to expand, 4) supporting a global services infrastructure footprint rather than just aftermarket services, and 5) an upside risk could be if BHGE is extract greater synergies from the integration process than was originally expected.

Company description

The new BHGE has been positioned to have exposure across the entire energy landscape – serving upstream, midstream, and downstream sectors. The company will be divided into four product companies – Oilfield Services, Oilfield Equipment, Turbomachinery and Process Solutions, and Digital Solutions. These four product companies have 24 product lines and segments. The combined company will have the largest exposure to the Turbomachinery & Downstream Technology Solutions business (which was 52% of GE Oil & Gas revenues and 68% of segment profit in 2016) and artificial lift, completion tools, wireline, directional drilling, and specialty chemicals from BHI's legacy business. BHI still will retain a minority interest of 46.7% in its former pressure pumping business. The business mix will consist of some backlog driven businesses on GE's side with BHI's more services oriented business. GE Oil & Gas ended 2016 with a backlog of $21.7bn, while orders of 11,273 were down 27% y/y.

Figure 233: Reporting segment

Baker Hughes, a GE Company

Oilfield Services
- Most of traditional BHI business
- Directional drilling, MWD
- Fluids
- Wireline and surface logging
- Completion Systems
  - Well construction
  - Welbore intervention
- Artificial Lift - ESP, gas lift, RLS
- Chemicals
	Turbomachinery & Process Solutions
	- Gas turbines, compressors, modular LNG
	- Turboexpanders, heat exchangers
	- Steam turbines, recip compressors
	- Downstream valves and fuel gas systems
	- Accounted for approx 47% of GE O&G '15 rev
	  - major EBIT contribution (almost 70% in '15)
	- BHI Industrial Services
	- Includes brands such as NuovoPignone, Salof, Dresser, Thermodyn
	- LNG, refineries - important end markets

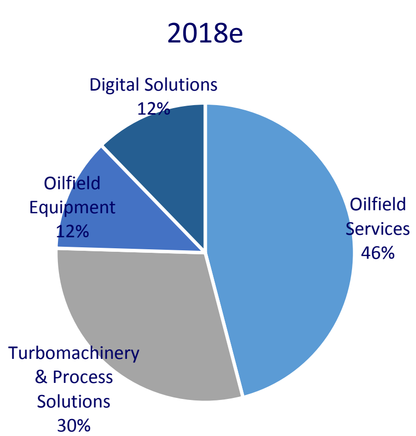
Oilfield Equipment - Drilling equipment - Subsea systems - trees, wellheads, manifolds downhole data acquisition, BOPs - Completion equipment - Includes brands such as Hydril, Vetco Gray - Flexible pipeline systems - Pressure control	**Digital Solutions** - Monitoring - Inspection - Measurement equipment & services - Goal to improve machinery health - Also improve productivity of assets - Stepping stone to access PREDIX platform - BHI Pipeline & Processing Services - Accounted for 14% of GE O&G '15 revenues

Source: Company reports, Deutsche Bank

Different exposures

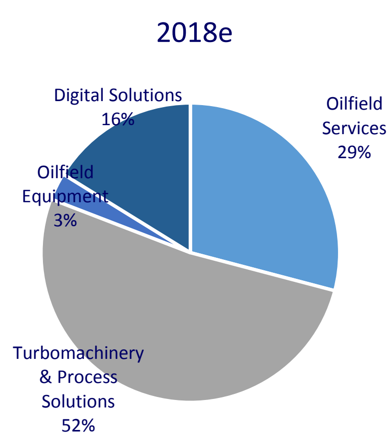
The legacy BHGE mostly lies within the Oilfield Services segment with the addition of GE's artificial lift business. The Oilfield Equipment segment mainly contains the old GE Oil & Gas Surface, Subsea & Drilling businesses. The Turbomachinery & Process Solutions segment is the same as the previous Turbomachinery & Downstream Technology Solutions. BHGE still will retain a minority interest of 46.7% in its former pressure pumping business. BHGE's business mix will consist of some backlog driven businesses on GE's side with BHI's more services oriented business. GE Oil & Gas ended 2016 with a backlog of $21.7bn, while orders of 11,273 were down 27% y/y.

Figure 234: BHGE 2018 forecasted segment revenues breakdown



Source: Deutsche Bank

Figure 235: BHGE 2018 forecasted segment EBIT breakdown



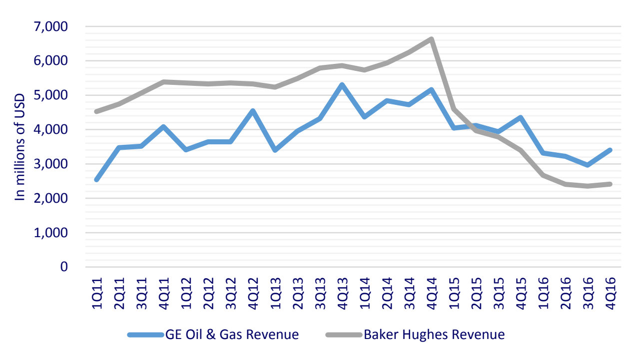
Source: Deutsche Bank

Historically, GE Oil & Gas offered its solutions through three main segments, Turbomachinery & Downstream Technology Solutions (TMDTS), Surface, Subsea & Drilling (SS&D), and Digital Solutions (DS). The business generated $3.1bn of revenue in 1Q17, of which 41% was generated from equipment and 59% from services. In FY16, the business generated $13.3bn in revenue, of which 46% from equipment and 54% from services. Of its three main segments, TMDTS is the largest and represented approximately 56% and 52% of total GE Oil & Gas revenue in 1Q17 and FY16 respectively. SS&D represented approximately 29% and 33% of total GE Oil & Gas revenue in 1Q17 and FY16 respectively. DS represented approximately 15% and 16% of total GE Oil & Gas revenue in 1Q17 and FY16 respectively.

In terms of regional exposures, BHI largest market historically had been North America but its Middle East/ Asia exposure had been growing the past few years and was almost 29% of total revenue in 4Q16. North America averaged about 43% of BHI revenue the past 10 years while Latin America was 10%, Europe/ Africa/ CIS is 22%, and 19% Middle East. In 2016, NAM was approximately 30% of revenue while the Middle East was almost 28%. The other regions were similar to their last 10 year averages. While GE Oil & Gas regional revenue in 2016 showed that its largest region was Middle East/ Africa at 26%, followed by US at 24%, Europe 19%, Asia 17%, and then Americas at 14%. Therefore the combined company largest regional exposure will be North America and Middle East/ Asia and the two regions will be relatively similar in size.

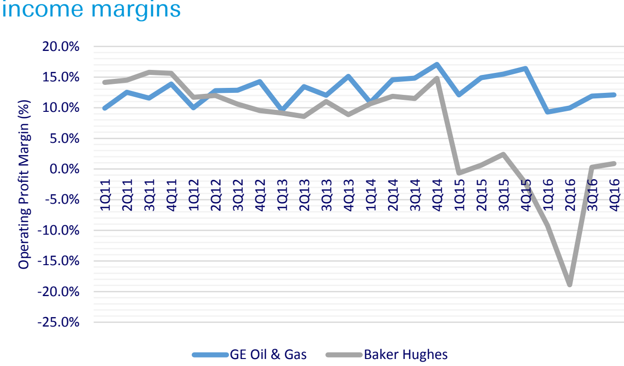
Also note that BHGE has a non-compete agreement with BJS in that it will not engage in any onshore pressure pumping business in the United States or Canada. This agreement is in place until BHGE's ownership stake in BJS is less than 20% (from the initial 46.7% stake) or if BHGE delivers a termination notice by some predetermined date. BHGE class A BJS common stock is also subject to a lock-up agreement.

Figure 236: Legacy BHI vs. GE Oil & Gas revenues



Source: Company reports

Figure 237: Legacy BHI vs. GE Oil & Gas operating income margins



Source: Company reports

Management profiles

Since this company was so recently formed, we have included brief management bios for its key leadership. The management team is fairly evenly distributed between former GE Oil & Gas executives with former BHI ones. Also the board members consisted of six being designated by GE and five from BHI.

Figure 238: Management bios

Name	Title	Prior Experience
Jeffrey Immelt	Chairman	Has been Chairman & CEO of GE since September 2001, but will retire from his CEO position on July 31, 2017. He will remain Chairman of GE through December 31.
Martin Craighead	Vice Chairman	Was Chairman & CEO of BHI since January 2012. Prior to that, he was President and COO from 2009-2012 and group President of Drilling and Evaluation from 2007-2009.
Lorenzo Simonelli	President & CEO	Prior to this role, had been President and CEO of GE Transportation for the past 5 years. Also had served as CFO Americas for GE Consumer & Industrial. He joined GE financial management program in 1994.
Maria Claudia Borras	President & CEO, Oilfield Services	She is a 25 year energy veteran, 20 of which was spent at Baker Hughes. In January 2015, she moved to GE to become COO of GE Oil & Gas. At BHI she was President Latin America from 2013-2015.
Belgacem Chariag	COO	He had been President, Global Operations for BHI and Chief Integration Officer. Prior to that he was President Global Products and Services and served as President Eastern Hemisphere from 2009-2013.
Matthias Heilmann	President & CEO, Digital Solutions	20 year industry veteran, was previously Chief Digital Officer at GE Oil & Gas. Before joining GE he led ABB's global product group enterprise software business.
Derek Mathieson	CTO	Was Chief Commercial Officer for BHI since May 2016 and before that was Vice President, Chief Technology Officer from September 2015-May 2016. He joined BHI in 2008 from WellDynamics.
Brian Worrell	CFO	Was most recently CFO of GE Oil & Gas, a position he held since January 2014. Previously had worked as Vice President corporate financial planning and before that in audit. He joined GE in 1992.

Source: Company reports

GE "definitions"

Predix = GE's proprietary operating system for the industrial internet by connecting industrial equipment, analyzing data, and deliver real-time insights. Example of applications include asset performance management, production optimization, optimize maintenance, and process optimization.

GE Store = Enables cross business collaboration by providing a forum that shares technology, markets, structure, and learnings. One example of utilizing the GE store was in a recent company presentation that showed how AutoTrak could be improved by the GE Store utilizing improvements in battery technology, GE Healthcare sensor analytics, fluid mechanics science, material science, and sensors to enhance the drilling process.

Principal Sources and Uses of Cash

Pro forma estimated synergies

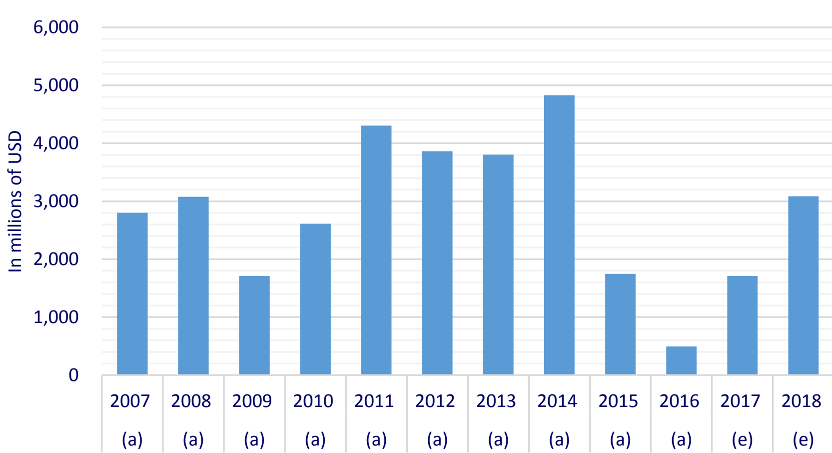
GE Oil & Gas management estimated synergies of $1.2bn which included $400mm in annual savings from sourcing and procurement improvements by 2020, $200mm from manufacturing and service footprint rationalization, $200mm from process optimization, and $400mm in SG&A consolidation. They also estimated revenue synergies of $400mm. Management believes the combined company can drive material deflation given its size and scale to secure the $400mm in sourcing and procurement savings. Consolidating its properties across its global footprint drives the $200mm while using GE's advanced manufacturing and digital condition-based maintenance drivers another $200mm savings. The other estimated $400mm comes from SG&A consolidation by right size back office and eliminating duplication. The challenge will be squeezing out some of these synergies given the company had very little overlap and the different model between manufacturing and services. The timeline for the cost synergies was approximately $600mm in 2018, $1bn in 2019, and $1.2bn in 2020.

Sources and uses of cash

BHI historically has used cash to fund working capital, capex, R&D (spent $384mm in R&D in 2016, a similar to level to what GE O&G spent), and paydown debt. The big spike in the free cash flow history was due to receiving the $3.5bn HAL merger breakup fee. BHI used some of those proceeds to pay down its own debt levels. Sources of cash have been its own cash flow from operations and debt. In 2016, BHI the Middle East/ Asia region was the only positive contributor to operating income of $186mm. North America was the largest operating loss region at $687mm, down 8% y/y. Its pressure pumping operations incurred share reductions and impacted results. If you look at BHI's capex history, post the BJS acquisition, capex started to go higher in 2010-2012 timeframe. Also BHI income tax expense continues to be impacted by the geographic mix, valuation allowances, and discrete tax items.

Management originally had set in its proforma estimates in the prospectus a target 2018 EBITDA of $5.5bn. Based on current market conditions, the lower than expected 2017 exit rate, and our view on spending and rig count growth in 2018, we estimate that BHGE will generate $3.1bn of EBITDA in 2018. We do expect management will try to pull forward the benefit of cost synergies to try partially offset the weaker operating environment.

Figure 239: BHGE consolidated EBITDA



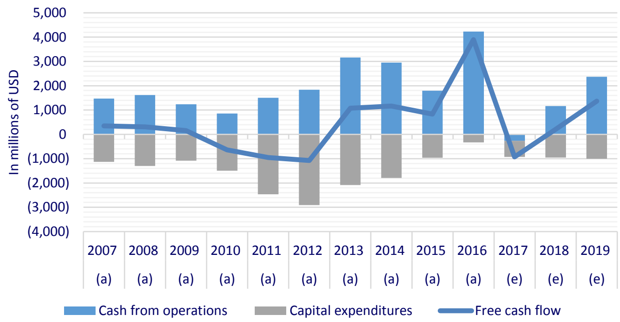
Source: Company reports, Deutsche Bank

Balance sheet and FCF

Q3 will be the first quarter in which the new BHGE will report consolidated results. Capital allocation priorities will also be important to watch. Management has said that they see the opportunity to increase leverage but seems like they want to protect their investment grade rating. While they are still assessing the correct capital allocation priorities, management has said that they expect to return 40 to

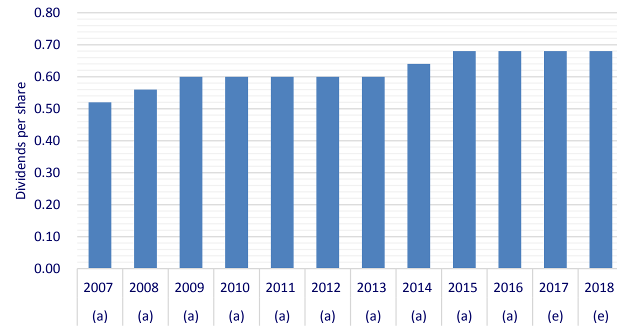
50% of net income to shareholders over time. Given concerns around GE's ability to generate cash, investors will be watching if BHGE is used as a vehicle to return cash to GE through an increasing dividend.

Figure 240: Recovery in shorter cycle businesses helps FCF improve



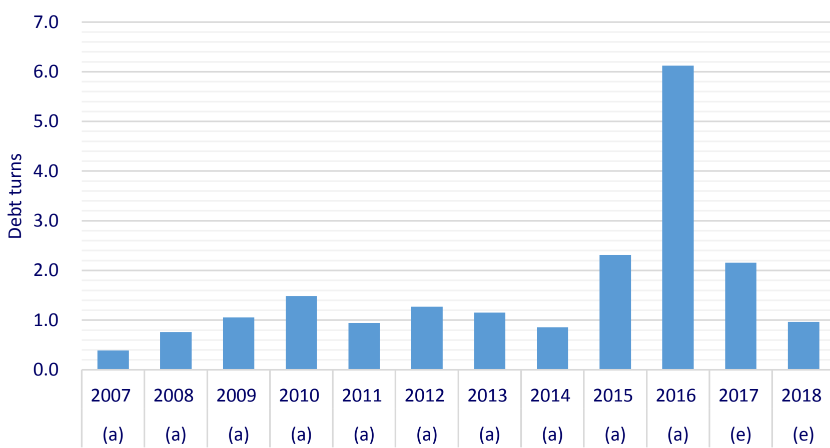
Source: Company reports, Deutsche Bank

Figure 241: Will BHGE look to increase its dividend



Source: Company reports, Deutsche Bank

Figure 242: Debt turns



Source: Company reports, Deutsche Bank

Figure 243: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenue													
North America	4,440	5,178	3,584	6,732	10,257	10,836	10,878	12,078	6,009	13,292	5,431	7,239	7,329
Latin America	903	1,127	1,133	1,576	2,183	2,399	2,307	2,236	1,799	12,001	2,127	2,674	2,925
Europe/CIS/Africa	3,076	3,386	2,925	3,048	3,325	3,634	3,902	4,417	3,278	12,647	2,986	3,357	3,590
Middle East/Asia	2,008	2,172	2,022	2,276	2,820	3,275	3,998	4,456	3,441	15,744	7,380	9,587	10,226
Eliminations, other	0	0	0	782	1,246	986	1,279	1,364	1,215	(43,843)	(1,985)	1,032	1,032
Total revenues	10,428	11,863	9,664	14,414	19,831	21,130	22,364	24,551	15,742	9,841	15,938	23,890	25,101
Op costs	6,323	7,314	6,439	10,121	13,873	15,452	16,700	17,852	12,338	8,149	12,383	18,665	19,946
SG&A	933	1,046	1,120	1,250	1,190	1,316	1,306	1,257	1,173	815	1,642	2,141	1,454
R&D	372	426	397	429	462	497	556	613	483	384	201	0	0
D&A	521	638	711	1,065	1,321	1,548	1,698	1,814	1,742	1,166	1,001	1,107	1,086
EBIT	2,279	2,440	997	1,549	2,985	2,317	2,104	3,015	6	(673)	711	1,976	2,616
Interest (expense)	(66)	(89)	(131)	(143)	(221)	(210)	(234)	(232)	(217)	(178)	(135)	(122)	(89)
Interest income	44	27	6	2	0	0	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	0	0	0	0	0	(62)	56	60
Other income	0	0	0	0	0	0	0	0	0	0	20	175	200
PBT	2,257	2,378	872	1,408	2,764	2,107	1,870	2,783	(211)	(851)	534	2,085	2,787
Income tax (expense)	(743)	(695)	(281)	(513)	(919)	(674)	(625)	(936)	(6)	75	(263)	(584)	(780)
Non-controlling interest	0	0	0	(7)	(4)	(6)	(7)	(12)	7	(2)	(218)	(938)	(1,254)
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	1,514	1,682	591	888	1,841	1,427	1,238	1,835	(210)	(778)	53	563	753
Discontinued ops	0	0	0	0	0	17	0	0	0	0	0	0	0
Unusual after-tax	0	(47)	(170)	(75)	(102)	(133)	(142)	(130)	(1,757)	(1,441)	(230)	0	0
Net income (GAAP)	**1,514**	**1,635**	**421**	**812**	**1,739**	**1,311**	**1,096**	**1,705**	**(1,967)**	**(2,219)**	**(177)**	**563**	**753**
Operating EPS	**4.73**	**5.45**	**1.90**	**2.25**	**4.20**	**3.24**	**2.79**	**4.18**	**(0.48)**	**(1.79)**	**0.12**	**1.31**	**1.75**
GAAP EPS	4.73	5.30	1.36	2.06	3.97	2.98	2.47	3.89	(4.49)	(5.11)	(0.41)	1.31	1.75
DPS	0.52	0.56	0.60	0.60	0.60	0.60	0.60	0.64	0.68	0.68	0.68	0.68	0.68
Diluted shares	320	309	311	395	438	441	444	439	438	434	430	430	430
EBITDA	**2,800**	**3,077**	**1,708**	**2,614**	**4,306**	**3,865**	**3,802**	**4,829**	**1,748**	**493**	**1,712**	**3,083**	**3,702**
EBITDA margin	26.9%	25.9%	17.7%	18.1%	21.7%	18.3%	17.0%	19.7%	11.1%	5.0%	10.7%	12.9%	14.7%
EBIT margin	21.9%	20.6%	10.3%	10.7%	15.1%	11.0%	9.4%	12.3%	0.0%	-6.8%	4.5%	8.3%	10.4%
Tax rate	32.9%	29.2%	32.2%	36.4%	33.2%	32.0%	33.4%	33.6%	-2.8%	8.8%	49.2%	28.0%	28.0%

Source: Company reports, Deutsche Bank

Figure 244: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	1,514	1,682	591	888	1,841	1,427	1,238	1,835	(210)	(778)	53	563	753
Depreciation	521	638	711	1,065	1,321	1,548	1,698	1,814	1,742	1,166	1,001	1,107	1,086
Deferred tax	(4)	(4)	(256)	(188)	(492)	(114)	0	0	0	0	0	0	0
Chg in receivables	(287)	(484)	399	(702)	(1,024)	16	(453)	(524)	1,943	762	(323)	77	434
Chg in inventories	(142)	(371)	240	(243)	(641)	(547)	(120)	(259)	1,092	293	(580)	(35)	107
Chg in payables	26	242	(89)	292	314	(94)	845	291	(1,349)	(360)	559	297	238
Other	(154)	(89)	(357)	(255)	188	(401)	(47)	(204)	(1,422)	3,146	(975)	(840)	(243)
Cash from operations	1,475	1,614	1,239	856	1,507	1,835	3,161	2,953	1,796	4,229	(265)	1,169	2,374
Capital expenditures	(1,127)	(1,303)	(1,086)	(1,491)	(2,461)	(2,910)	(2,085)	(1,791)	(965)	(332)	(667)	(956)	(1,004)
Free cash flow	348	311	153	(635)	(954)	(1,075)	1,076	1,162	831	3,897	(932)	214	1,370
Acquisitions	0	(120)	(58)	(888)	(5)	0	0	(314)	0	0	0	0	0
Asset sales	189	253	163	247	311	389	455	437	388	283	134	0	0
Dividends paid	(166)	(173)	(185)	(241)	(261)	(263)	(267)	(279)	(297)	(293)	(292)	(292)	(292)
ESPP | options	68	87	0	0	0	0	0	0	0	0	0	0	0
Equity issuance, net	(522)	(627)	51	74	183	81	(249)	(384)	116	(672)	60	0	0
Debt issuance, net	14	1,235	(541)	1,531	54	847	(571)	(248)	(45)	(1,195)	(10)	(723)	0
Other	177	(65)	57	23	16	(14)	(60)	(33)	(409)	228	975	0	0
Chg in cash	107	901	(360)	111	(656)	(35)	384	341	584	2,248	(65)	(802)	1,077
FCF per share	2.16	2.04	1.53	1.40	1.86	1.88	1.23	0.99	0.55	0.28	0.67	0.86	0.92
Capex / revenue	0.11	0.11	0.11	0.10	0.12	0.14	0.09	0.07	0.06	0.03	0.04	0.04	0.04
Capex / depreciation	2.16	2.04	1.53	1.40	1.86	1.88	1.23	0.99	0.55	0.28	0.67	0.86	0.92

Source: Company reports, Deutsche Bank

Figure 245: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	1,054	1,955	1,595	1,706	1,050	1,015	1,399	1,740	2,324	4,572	4,507	3,705	4,783
Accounts receivable	2,383	2,759	2,331	3,942	4,878	4,815	5,138	5,418	3,217	2,251	5,089	5,012	4,578
Inventories	1,714	2,021	1,836	2,594	3,222	3,781	3,884	4,074	2,917	1,809	5,585	5,620	5,514
Deferred taxes	182	231	268	234	251	266	380	418	301	0	0	0	0
Other current assets	122	179	195	231	396	540	494	395	509	535	1,199	1,309	1,340
Total current assets	5,456	7,145	6,225	8,707	9,797	10,417	11,295	12,045	9,268	9,167	16,380	15,646	16,215
Net PP&E	2,345	2,833	3,161	6,310	7,415	8,707	9,076	9,063	6,693	4,271	6,296	6,144	6,062
Goodwill	1,354	1,389	1,418	5,869	5,956	5,958	5,966	6,081	6,070	4,084	19,111	19,111	19,111
Other assets	702	494	635	2,100	1,679	1,607	1,597	1,638	2,049	1,512	13,150	14,351	14,698
Total assets	9,857	11,861	11,439	22,986	24,847	26,689	27,934	28,827	24,080	19,034	54,937	55,252	56,086
Accounts payable	704	888	821	1,496	1,810	1,737	2,574	2,807	1,409	1,027	3,643	3,940	4,177
Income taxes payable	457	530	448	589	704	646	778	782	690	566	443	483	495
Dividends payable	191	272	95	219	289	226	213	265	55	78	0	0	0
Current debt	15	558	15	331	224	1,079	499	220	151	132	964	241	241
Other current liabilities	251	263	234	504	475	436	514	563	470	501	3,366	3,673	3,762
Total current liabilities	1,618	2,511	1,613	3,139	3,502	4,124	4,578	4,637	2,775	2,304	8,415	8,337	8,675
Long-term debt	1,069	1,775	1,785	3,554	3,845	3,837	3,882	3,913	3,890	2,886	2,727	2,727	2,727
Deferred taxes	416	384	309	1,360	810	745	821	740	252	328	1,283	1,283	1,283
Employee obligations	332	317	379	483	578	579	583	629	646	626	1,117	1,117	1,117
Other LT liabilities	116	67	69	164	148	136	158	178	135	153	1,345	1,468	1,503
Non-controlling int	0	0	0	186	218	199	199	105	84	81	25,051	25,989	27,244
Shareholders' equity	6,306	6,807	7,284	14,100	15,746	17,069	17,713	18,625	16,298	12,656	14,999	14,331	13,537
Total liabilities and equity	9,857	11,861	11,439	22,986	24,847	26,689	27,934	28,827	24,080	19,034	54,937	55,252	56,086
Total debt	1,085	2,333	1,800	3,885	4,069	4,916	4,381	4,133	4,041	3,018	3,691	2,968	2,968
Net debt	30	378	205	2,179	3,019	3,901	2,982	2,393	1,717	(1,554)	(816)	(737)	(1,815)
Debt/capital	15%	26%	20%	22%	21%	22%	20%	18%	20%	19%	20%	17%	18%
Debt/equity	17%	34%	25%	28%	26%	29%	25%	22%	25%	24%	25%	21%	22%
Debt turns	**0.4**	**0.8**	**1.1**	**1.5**	**0.9**	**1.3**	**1.2**	**0.9**	**2.3**	**6.1**	**2.2**	**1.0**	**0.8**

Source: Company reports, Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Basic Energy Services Inc

Reuters	Bloomberg
BAS.N	BAS US

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Research Analyst
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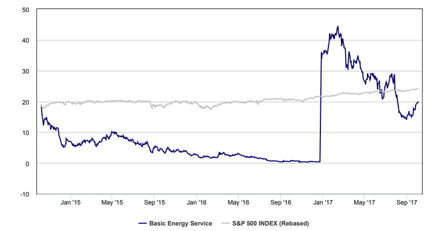
Price at 5 Oct 2017 (USD)	19.77
Price target	22.00
52-week range	44.50 - 0.32

Price/price relative



Performance (%)	1m	3m	12m
Absolute	28.5	-25.7	2,407.7
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	511.7
Shares outstanding (m)	25.9
Free float (%)	100
Volume (5 Oct 2017)	176,441
Option volume (und. shrs., 1M avg.)	68,258

Source: Deutsche Bank

Increasing Exposure to Completion Markets

Initiating coverage with a Hold rating and a $22 price target

We are initiating coverage of Basic Energy Services with a Buy rating and a $22 price target. Despite its solid position in the well servicing market, operators have been slow to spend on opex and have deferred maintenance spending. Management wisely has increased exposure to completion markets which has helped to partially offset the slower recovery in well servicing. If E&Ps truly focus on living within cash flow, then enhancing existing production might start to see some spending shake loose given its quick cash conversion. Management has shown a willingness in the past to divest non-core assets or act as a consolidator to increase its scale.

Changing earnings profile with increasing exposure to completion markets

BAS has become more diversified as it increased its exposure to completion markets both through organic growth and acquisitions. In the current upcycle, completion activity has recovered much faster and has become a larger part of BAS' overall business. The company typically concentrates on the market below the larger players, focusing on underserved smaller customers who are doing smaller frac jobs. This increasing exposure to completion activity will change the earnings profile as its Completion segment now accounts for almost 50% of total revenues.

Improved balance sheet post bankruptcy but has working capital needs

BAS emerged from bankruptcy with an improved balance sheet, but responding quickly to the upcycle has led to working capital needs.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-1.36	-0.87A	–
2Q EPS	-1.34	-0.57	–
3Q EPS	-1.91	-0.38	–
4Q EPS	-1.18	-0.22	–
FY EPS (USD)	-5.80	-2.05	-0.35
OLD FY EPS (USD)	-5.80	-2.03	0.60
% Change	-0.0%	0.8%	-159.1%
P/E (x)	–	–	–
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	547.5	867.0	1,052.9

Source: Deutsche Bank estimates, company data

Valuation

Our $22 price target is based on 6.0x EV/ EBITDA multiple of our 2018 EBITDA estimate. Our target multiple is based on a one-year forward relative (to the S&P 500) EV/ EBITDA multiple applied to the historical average through-cycle EV/ EBITDA multiple for BAS.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) a step up in cost inflation in the US, 3) a swift increase in new frac capacity in the US, and 4) an upside risk is opex spending on well maintenance might finally start to shake loose as older horizontal wells mature.

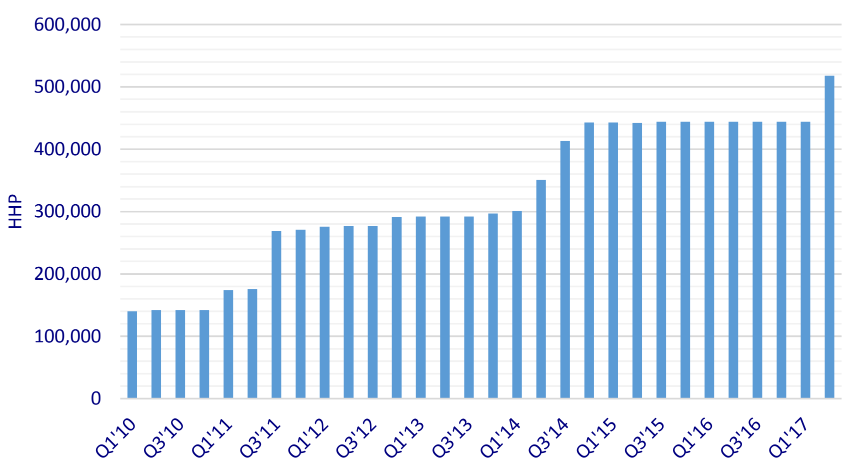
Key investment themes

Increasing exposure to completion services

BAS has used a combination of organic growth, acquisitions, and ordering new equipment to increase their exposure to completion services. It was a smart decision strategically for the company as operators have deferred maintenance spending which has impacted their legacy production oriented services in this cycle. It also enabled BAS to become more of a diversified player with the ability to offer services across the well lifecycle. Its Completion & Remedial Services segment (pressure pumping, rental and fishing tools, coiled tubing, snubbing) has grown given the improvement in completion directed spending and now makes up approximately 50% of total revenues, up from 30% back in early 2016.

BAS typically concentrates on working for smaller customers by providing mid-sized fracturing services in a few selected markets and generally does not participate in 24-hour, multi wells on a pad jobs. Even still BAS has been able to drive both revenue and margin growth in this segment due to the growth in well counts in this upcycle, operators working down their backlog of uncompleted wells, and BAS own pressure pumping capacity growth. This changes the earnings profile of the company due to its increased exposure to completion services.

Figure 246: BAS nameplate pressure pumping horsepower



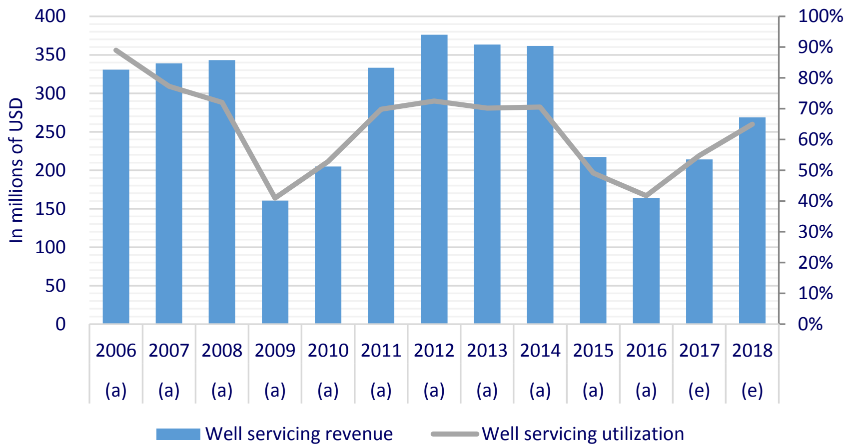
Source: Company reports, Deutsche Bank

Maintenance spending and opex continues to be deferred

Traditionally, BAS has been a large player in the well servicing market which provided maintenance related services for customers needing to perform periodic upkeep of producing oil and gas wells. This work primarily focuses on extending the life of a well and improving the ultimate recovery. Operators used to focus on this work as it generated high returns for relatively small opex spending. The difference in this recovery is that operators have continued to focus their activity and spending on drilling and completion activities and have deferred well maintenance spending. Even though well servicing utilization has improved, the rate of change has been lower than historically what one would have expected to see at this point in the cycle.

The backlog of horizontal oil wellbores have increased after almost 10 years of drilling tight oil plays in the US onshore. As these wells continue to age, they will require maintenance services. However, when thinking about why maintenance spending levels have not returned to historical levels, one has to wonder if the improving efficiencies and well productivity will continue to make operators focus more on drilling and completion work. This leaves the well servicing rig market with a lot of overcapacity and we would expect to see additional consolidation.

Figure 247: Well servicing revenue vs. rig utilization



Source: Company reports, Deutsche Bank

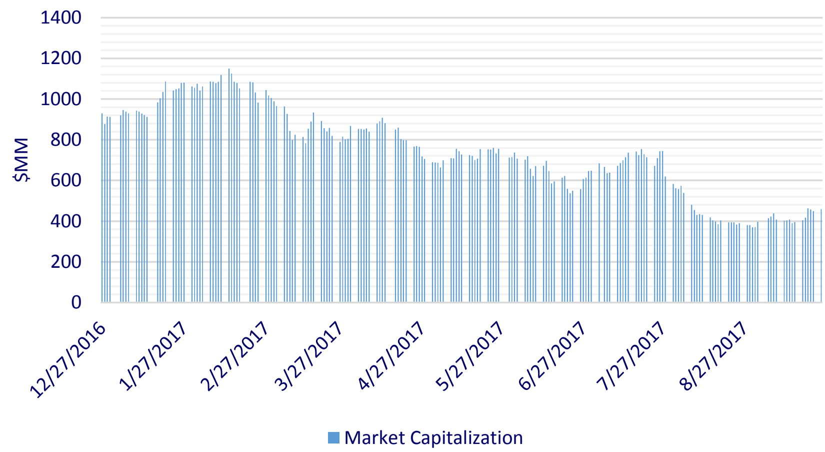
Improved balance sheet post emergence from bankruptcy

BAS was able to emerge from bankruptcy late in 4Q16 with an improved balance sheet. While the company has no debt maturities until 2021, working capital was needed to respond to the upcycle and it has been a drain on liquidity. If the upcycle starts to slow or reverse, liquidity issues might resurface. At the end of 2Q17, BAS had $34mm cash on its balance sheet.

Under the radar small cap

Several smid cap players that have exposure to well servicing and fluid hauling markets went bankrupt during the most recent downturn. Post emergence from bankruptcy and even with some of these companies keeping their original tickers, it seems like these companies have been flying a little bit under the radar. Part of it is due to fewer analysts covering these companies post-bankruptcy. The other factor is BAS now has a $450mm market cap, which is smaller than many professional investors will look at.

Figure 248: BAS market cap since emerging from bankruptcy

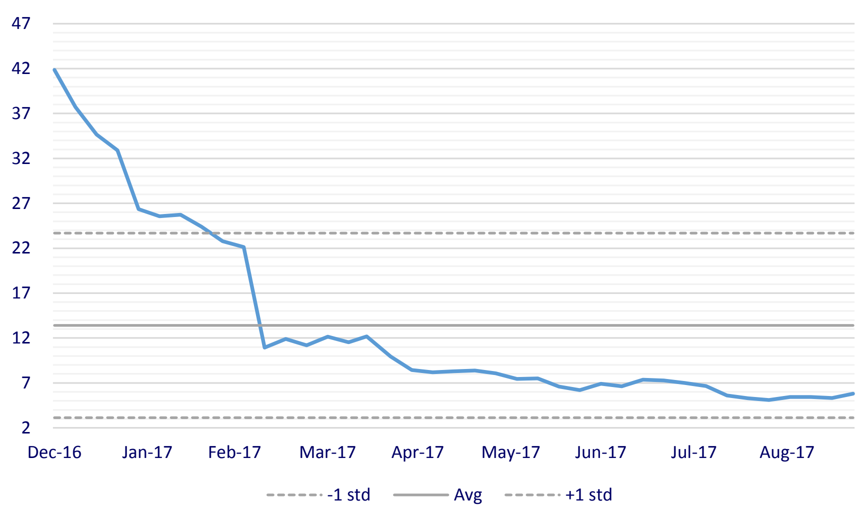


Source: Bloomberg Finance LP

Valuation and risks

Our price target is based on 6.0x EV/ EBITDA multiple of our 2018 EBITDA estimate. Our target multiple is based on a one-year forward relative (to the S&P 500) EV/ EBITDA multiple applied to the historical average relative through-cycle EV/ EBITDA multiple for BAS. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) a step up in cost inflation in the US, 3) making an acquisition that consolidates challenging parts of the market, and 4) an upside risk is opex spending on well maintenance might finally start to shake loose as older horizontal oil wells require maintenance that has been deferred.

Figure 249: EV/ EBITDA since emerging from bankruptcy

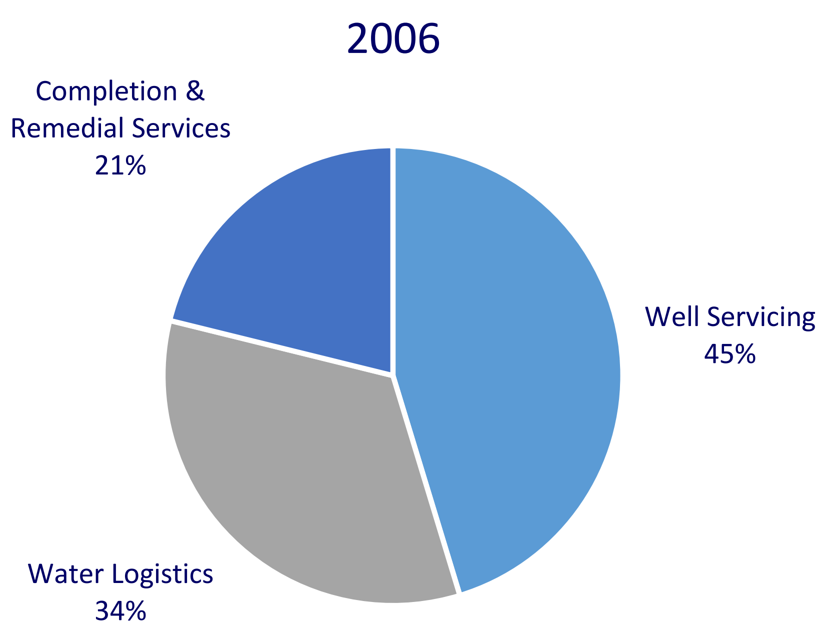


Source: Factset

Company description

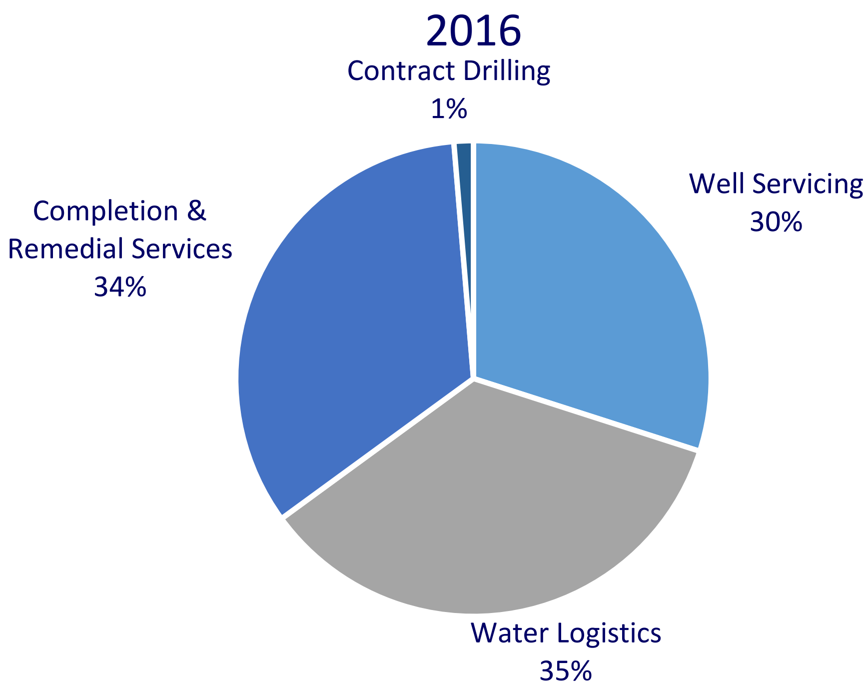
Basic Energy Services can trace its history back 25 years and is currently one of the largest well service companies in the US with operations in all major oil and gas production regions. BAS has been focused on growing its well completion business, in which they provide a wide range of services to help get their customers ready for production. In addition, BAS provides a full offering of well maintenance services on aging producing wells. Basic filed for bankruptcy in October 2016 before re-emerging in December with a cleaned up balance sheet that saw debt levels reduced by $813mm along with an improved liquidity position.

Figure 250: Changing revenue mix towards completion



Source: Company reports

Figure 250: Changing revenue mix towards completion



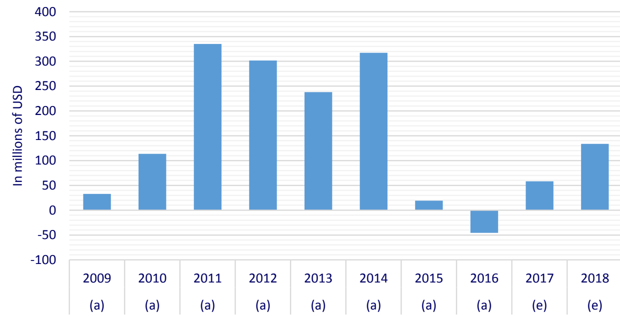
Source: Company reports

Principal Sources and Uses of Cash Flow

The primary contributors to EBITDA are mainly its Completion & Remedial Services and its Water Logistics segments. As we previously discussed, its Completion segment has been driven by higher utilization and improved pricing for completion services. In Water Logistics, volumes of water being used in frac plays has been increasing in shale development for the past few years as operators use larger completion sizes. Well Servicing has started to seeing improving utilization more recently and should start to contribute more to EBITDA going forward.

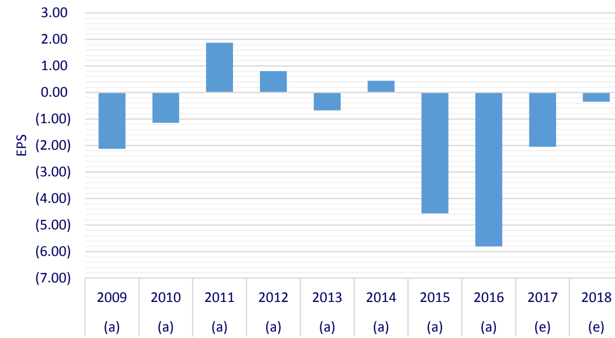
The primary uses of cash flow has been working capital and capex to fund reactivation of assets that were stacked during the downturn. BAS has also purchased equipment in its efforts to respond to the improving industry utilization levels. While BAS has no newbuild commitments, the company purchased 74k of pressure pumping capacity in 1Q17. With no near term debt maturities until 2021, we do not expect debt pay-down to consume much capital over the near-term. Capex for 2017 is expected to be around $115mm, with approximately $70mm going towards maintenance spending.

Figure 251: Consolidated EBITDA expected to turn positive in 2017



Source: Company reports, Deutsche Bank

Figure 252: Earnings remain negative

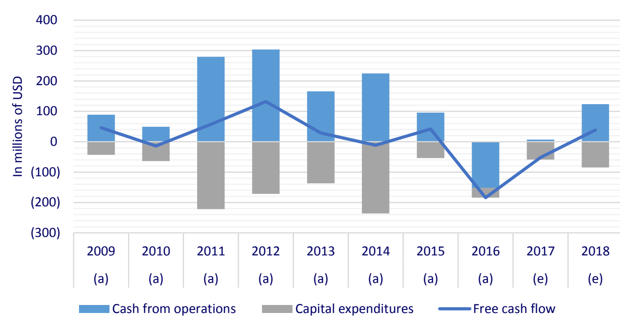


Source: Company reports, Deutsche Bank

Balance Sheet and FCF

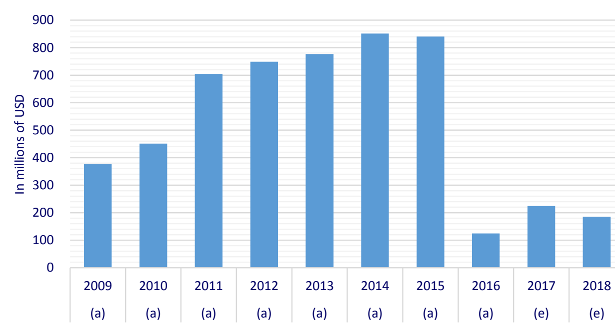
BAS emerged from bankruptcy proceedings in December with an improved balance sheet after reducing debt levels by $813mm. The company also has no debt maturities until 2021, but it did burn approximately $50mm of cash in Q1 and $16mm in Q2. Working capital continues to be a significant user of cash as the company looks to respond to the rapidly rebounding market. In addition, BAS recently purchased frac assets and will need to spend some capital on reactivation and maintenance for the equipment. If the upcycle starts to slow or reverse, liquidity issues might resurface.

Figure 253: Free cash flow remains negative in 2017



Source: Company reports, Deutsche Bank

Figure 254: Improved debt levels post bankruptcy



Source: Company reports, Deutsche Bank

Figure 255: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Segment revenues												
Well Servicing	339	343	161	205	333	376	363	362	217	164	214	269
Water Logistics	259	316	215	241	332	352	344	370	259	192	205	217
Completion & Remedial Services	241	304	135	261	537	586	501	699	308	185	437	550
Contract Drilling	38	42	16	21	41	60	55	61	22	7	10	17
Total revenues	877	1,005	527	728	1,243	1,375	1,263	1,491	806	547	867	1,053
Segment gross profit												
Well Servicing	134	128	39	48	104	108	98	91	32	24	46	67
Water Logistics	94	113	56	63	120	116	105	105	62	30	40	48
Completion & Remedial Services	115	139	40	105	240	228	174	264	62	26	107	158
Contract Drilling	15	13	3	6	13	20	18	19	6	0	1	3
Total gross profit	358	392	137	221	477	472	395	480	163	80	194	276
SG&A	99	115	104	108	142	170	157	163	143	125	136	143
EBITDA	259	277	33	114	335	302	238	317	19	(45)	58	134
D&A	93	119	133	135	154	187	210	217	241	213	105	110
EBIT	166	158	(100)	(21)	181	115	28	100	(222)	(259)	(46)	24
Interest (expense), net	(25)	(25)	(32)	(46)	(52)	(62)	(67)	(67)	(68)	(86)	(38)	(38)
Other Income (expense)	0	5	1	2	1	(9)	(8)	(14)	(25)	70	0	0
PBT	141	139	(131)	(66)	129	43	(47)	19	(315)	(275)	(84)	(14)
Income tax (expense)	(53)	(55)	47	25	(51)	(10)	20	(1)	131	31	31	5
Net Income (operating)	88	84	(84)	(41)	78	33	(27)	18	(184)	(244)	(53)	(9)
Discontinued Ops	0	0	0	0	0	0	0	0	0	0	0	0
Unusual after-tax	(1)	(15)	(210)	(2)	(30)	(12)	(9)	(26)	(58)	(174)	(1)	0
Net Income GAAP	**88**	**68**	**(294)**	**(44)**	**47**	**21**	**(36)**	**(8)**	**(242)**	**(418)**	**(54)**	**(9)**
Operating EPS	**2.15**	**2.01**	**(2.12)**	**(1.04)**	**1.87**	**0.81**	**(0.68)**	**0.44**	**(4.56)**	**(5.80)**	**(2.05)**	**(0.35)**
GAAP EPS	2.13	1.65	(7.42)	(1.10)	1.14	0.51	(0.89)	(0.20)	(6.00)	(9.94)	(2.08)	(0.35)
DPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diluted shares	41	42	40	40	42	41	40	41	40	42	26	26
Consolidated EBITDA	259	277	33	114	335	302	238	317	19	(45)	58	134
EBITDA margin	29.6%	27.6%	6.2%	15.6%	26.9%	22.0%	18.8%	21.3%	2.4%	-8.3%	6.7%	12.7%
EBIT margin	18.9%	15.8%	-18.9%	-2.9%	14.5%	8.3%	2.2%	6.7%	-27.6%	-47.3%	-5.4%	2.3%
Tax rate	37.6%	44.6%	13.7%	36.3%	52.0%	32.3%	35.4%	-6.6%	35.2%	6.9%	36.9%	36.0%
Segment gross margins												
Well Servicing	39.6%	37.3%	24.3%	23.4%	31.3%	28.7%	27.1%	25.3%	14.9%	14.4%	21.4%	25.0%
Water Logistics	36.2%	35.6%	25.9%	26.1%	36.2%	32.8%	30.5%	28.3%	24.1%	15.7%	19.4%	22.2%
Completion & Remedial Services	47.7%	45.6%	29.3%	40.1%	44.7%	38.9%	34.6%	37.8%	20.3%	14.0%	24.5%	28.7%
Contract Drilling	39.9%	31.4%	16.9%	26.6%	31.4%	34.0%	33.3%	31.8%	24.9%	2.2%	12.5%	15.5%

Source: Company reports, Deutsche Bank

Figure 256: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Net Income	88	68	(254)	(44)	47	21	(36)	(8)	(242)	(456)	(78)	(9)
D&A	93	119	133	135	154	187	210	217	241	218	105	110
Deferred tax	15	30	(25)	(6)	31	12	(20)	0	(131)	(4)	0	0
Change in working capital	(5)	(32)	5	(45)	(8)	57	(7)	(38)	126	55	(36)	22
Other	8	28	230	9	56	27	19	53	101	36	16	0
Cash from operations	199	213	89	49	279	304	166	225	96	(151)	7	124
Capital expenditures	(99)	(92)	(43)	(64)	(222)	(171)	(137)	(236)	(54)	(33)	(59)	(85)
Free cash flow	100	121	46	(14)	58	132	29	(12)	42	(184)	(52)	39
Acquisitions	(200)	(114)	(8)	(50)	(218)	(85)	(21)	(16)	(17)	0	0	0
Asset sales	4	8	(12)	16	20	6	19	39	8	3	5	0
Dividends	0	0	0	0	0	0	0	0	0	0	0	0
Equity issuance, net	(0)	(3)	(6)	(0)	(2)	(18)	(4)	(8)	(5)	125	(0)	0
Debt issuance, net	134	6	2	(28)	184	27	(45)	(32)	(60)	80	(2)	0
Other	2	1	(8)	(0)	(11)	(5)	0	(3)	(1)	28	(0)	0
Chg in cash	41	19	14	(77)	31	56	(23)	(32)	(33)	52	(49)	39
FCF per share	2.43	2.91	1.16	(0.36)	1.39	3.20	0.71	(0.29)	1.03	(4.57)	(2.00)	1.48
Capex / revenue	0.11	0.09	0.08	0.09	0.18	0.12	0.11	0.16	0.07	0.06	0.07	0.08
Capex / depreciation	1.06	0.77	0.33	0.47	1.44	0.92	0.65	1.09	0.22	0.15	0.56	0.77

Source: Company reports, Deutsche Bank

Figure 257: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Cash and equivalents	92	111	125	48	78	135	112	80	47	99	50	88
Accounts receivable	138	173	86	150	255	209	204	247	102	109	172	153
Inventories	11	12	11	22	35	40	34	45	37	36	40	43
Other current assets	25	28	101	111	55	54	53	43	39	21	29	29
Total current assets	267	324	323	331	423	438	403	415	225	265	290	313
Net PP&E	637	741	667	626	856	944	928	1,008	846	489	492	467
Goodwill	205	203	3	16	83	106	111	78	0	0	0	0
Other assets	35	43	47	57	98	108	101	96	90	15	15	15
Total assets	1,144	1,311	1,040	1,030	1,460	1,596	1,543	1,597	1,161	768	798	795
Accounts payable	22	28	23	40	57	62	46	51	55	48	88	94
Current debt	17	26	26	24	34	38	41	49	49	38	46	46
Other current liabilities	52	48	43	55	65	78	78	97	66	53	58	58
Total current liabilities	92	102	92	119	156	178	165	196	170	140	193	199
Long-term debt	406	454	476	475	749	845	847	883	838	185	227	227
Other LT liabilities	120	159	132	134	195	199	187	176	47	29	31	31
Shareholders' equity	525	595	340	302	360	374	345	343	106	414	347	338
Total liabilities and equity	1,144	1,311	1,040	1,030	1,460	1,596	1,543	1,597	1,161	768	798	795
Total debt	424	480	502	499	783	883	888	931	887	223	274	274
Net debt	332	369	376	451	705	749	777	851	840	124	224	186
Debt/capital	45%	45%	60%	62%	69%	70%	72%	73%	89%	35%	44%	45%
Debt/equity	81%	81%	148%	165%	218%	236%	257%	272%	834%	54%	79%	81%
Debt turns	**1.6**	**1.7**	**15.3**	**4.4**	**2.3**	**2.9**	**3.7**	**2.9**	**46.0**	**NM**	**4.7**	**2.0**

Source: Company reports, Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
C&J Energy Services

Reuters	Bloomberg
CJ.N	CJ US

David Havens
Research Analyst
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Price at 4 Oct 2017 (USD)	29.56
Price target	39.00
52-week range	41.00 - 24.70

US Margin Leverage Now with Clean Balance Sheet

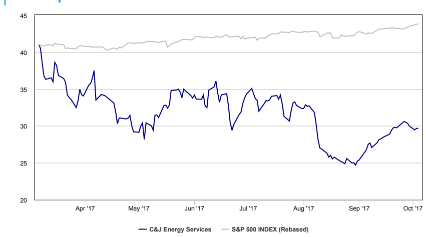
Initiating coverage with a Buy rating and a $39 price target

CJ has high operating leverage to the positive fundamentals in the US pressure pumping market, and now has a debt-free balance sheet. The US frac market is one of the few markets recreating scarcity value and pricing. While investors are all over the frac names given the limited alternatives elsewhere, we believe the opportunity set in US tight oil will carry demand for frac through 2018 despite our view that oil prices will be confined below $55. Up to $55 is still a strong driver of momentum. Discipline is required though, as this cycle is unlikely to run away with higher earnings like the prior two cycles.

CJ has a full frac calendar through year-end

CJ is reactivating equipment and has placed an order for 20 newbuild pumps that will take its capacity up to 900k hhp. The company plans on exiting 3Q17 with 575k hhp back in the field with a cadence of 1-2 fleets per quarter into 2018. We expect CJ can restore its EBITDA to $350m as soon as 2018.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	16.8	-15.4	–
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,790.2
Shares outstanding (m)	60.6
Free float (%)	–
Volume (4 Oct 2017)	136,173
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.60	-0.33A	0.39
2Q EPS	-1.11	-0.01	0.48
3Q EPS	-0.37	0.15	0.60
4Q EPS	-0.59	0.27	0.69
FY EPS (USD)	-2.68	0.13	2.16
OLD FY EPS (USD)	-7.98	-0.66	2.25
% Change	-66.4%	-118.9%	-3.9%
P/E (x)	–	236.2	13.7
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	–	0.0	0.0
Revenue (USDm)	971.1	1,660.9	2,270.7

Source: Deutsche Bank estimates, company data

Valuation & Risks

Our $39 price target is 6.5x our estimate of the company's normalized EBITDA power of $350 million, which is a 1.5 turn premium to the 5.0x five-year average multiple of its frac peers leading up to the 2014 collapse in oil prices. We apply this premium for CJ and its peers to account for the margin leverage and expansion opportunities. Furthermore, the company has no leverage, and is likely to grow its frac capacity and its normalized EBITDA above our current range.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a swift increase in new frac capacity in the US, and 4) and a subsequent move lower in pricing and margins.

Key investment themes

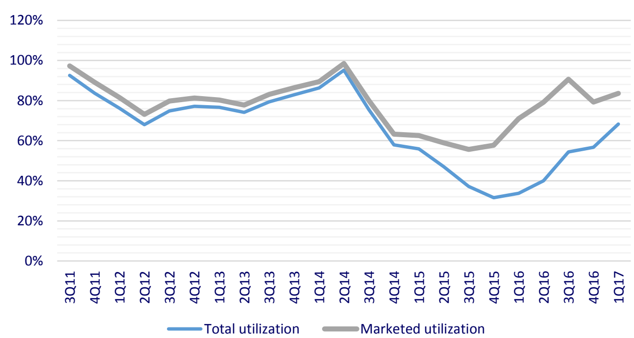
US pressure pumping market is undersupplied

The positive supply/demand trends are continuing in the frac market, driven by a rising well count, increased pad drilling, more wells per pad and an increasing inventory of DUCs (drilled but uncompleted wells). Frac fleets are also incorporating more hhp, averaging about 50k now. The increase is to accommodate the larger pads, which are keeping crews on location longer, thus in order to accommodate maintenance rotations and suitable uptime, contractors have increased fleet sizes.

CJ has been and continues reactivating idle capacity with plans to exit 3Q17 with 575k hhp deployed and a redeployment cadence of 1-2 fleets per quarter. The company also ordered 20 newbuild pumps and expects to have 900k of total hhp by 1Q18, up from 860k hhp in 2Q17.

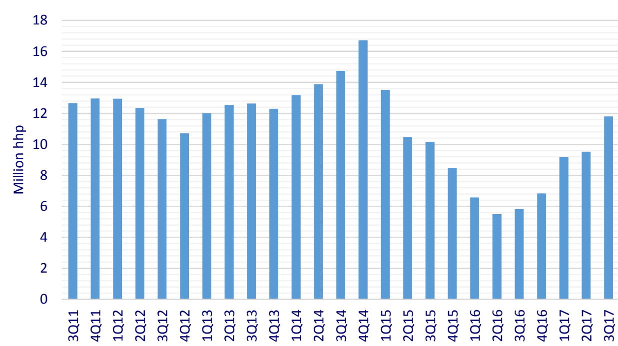
Demand industry-wide has recovered to about 12 million hhp versus 17 million at the peak, and less than 6 million at the trough. All available horsepower by and large is now booked through year-end 2017. Marketed utilization is back above 80% with some contractors suggesting the market is undersupplied by 1.5 – 2.0 million horsepower. CJ is being methodical about its redeployments, and is not looking to just grab utilization. We do expect the company will have about 600k hhp deployed by year-end and rising through 1H18.

Figure 258: Total vs. marketed frac hhp utilization



Source: IHS Markit, Deutsche Bank

Figure 259: US frac hhp demand

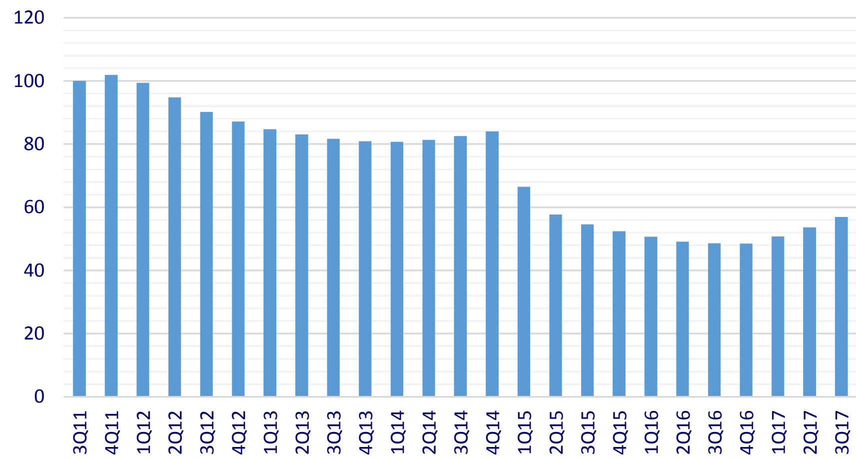


Source: IHS Markit, Deutsche Bank

Pricing moving higher, albeit more modestly

Pricing has improved, but more moderately than what some producers had previously expected. While several contractors are suggesting pricing is not yet at newbuild economics, newbuilds are coming, including about 100k hhp from RES and the 20 pumps from CJ.

Figure 260: US frac pricing indexed to 3Q11



Source: IHS Markit, Deutsche Bank

Attrition is increasing

Frac intensity on the larger pads and bigger wells is chewing equipment faster than last cycle, kicking attrition into a higher gear. Industry expectations for attrition are upwards of 3.5 million hhp per annum as useful lives decline and maintenance capital rises. While this is tightening the market upfront, it increases the capital intensity for the industry longer term.

Modest newbuilding, but likely to pickup

Newbuild lead times for frac spreads are about 9-12 months versus a high of 18 months last cycle. Newbuild costs are back up to $1,000/hhp with modest activity underway.

Well Support Services not getting the same traction

The Well Support Service business remains very competitive with limited ability to increase price. We are modeling flat pricing in 2018.

Valuation and risks

Our $39 price target is 6.5x our estimate of the company's normalized EBITDA power of $350 million, which is a 1.5 turn premium to the 5.0x five-year average multiple of its frac peers leading up to the 2014 collapse in oil prices. We apply this premium for CJ and its peers to account for the margin leverage and expansion opportunities. Furthermore, the company has no leverage, and is likely to grow its frac capacity and its normalized EBITDA above our current range.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a swift increase in new frac capacity in the US, and 4) and a subsequent move lower in pricing and margins.

Company description

C&J Energy Services (CJ) is a leading provider well construction, completions, workover rigs, and fluid management services. The company is a top ten provider of hydraulic fracturing services with approximately 860k horsepower. The company launched its first 34k hhp frac fleet in 2007, then followed up with another dozen fleets for a total of about 442k hhp. In 2015 the company combined with the completion and production services business of Nabors Industries, which took its frac fleet to over one million hhp, and added the Well Support Services business, which now includes 458 workover rigs, over 1,100 fluid trucks, and 29 salt water disposal wells.

Figure 261: Operating divisions

C&J Energy Services

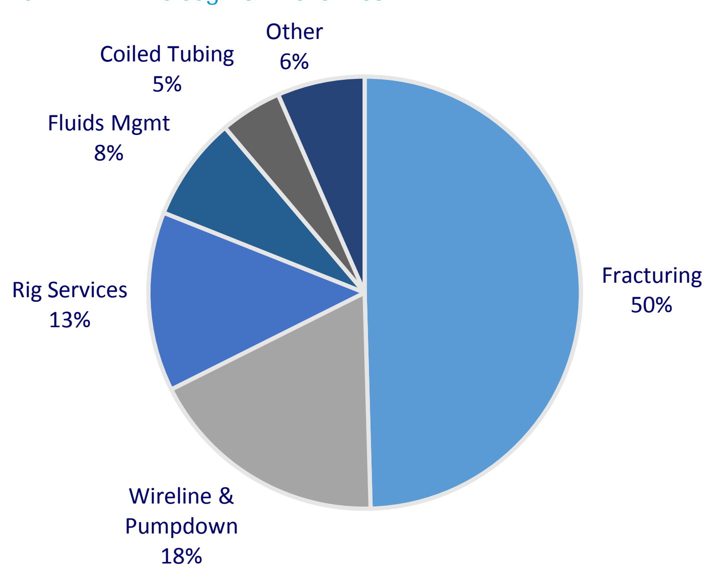
Completion Services
- Hydraulic fracturing
- Cased-hole solutions
  - Wireline and pumping
  - Wireline logging
  - Perforating
- Well construction and intervention
  - Cementing
  - Coiled tubing
  - Directional drilling services

Well Support Services
- Rig services
  - 458 workover rigs
- Fluids management
  - 1,121 fluid trucks
  - 29 salt water disposal wells (SWD)

Source: Company reports

Due to the severity of the oilfield downturn that began in late 2014, CJ filed for Chapter 11 bankruptcy in July 2016. The company emerged from Chapter 11 in January 2017 and now has zero debt on the balance sheet.

Figure 262: FY17 DBe segment revenues



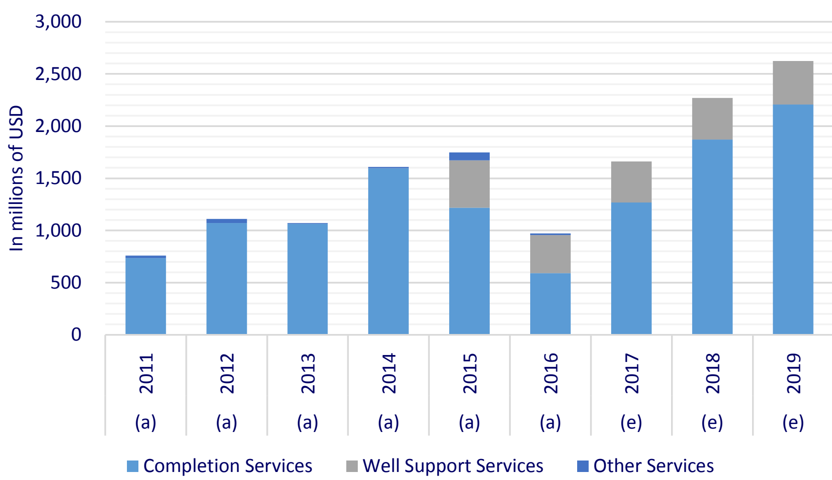
Source: Deutsche Bank

Principal Sources and Uses of Cash Flow

Core business is completions and well construction…US is principal market

CJ generates over 96% of its revenue from its US operations. Its Canadian exposure is generated by the completion and production services business acquired from Nabors Industries. After the exit of coiled tubing services in the Middle East, the only service line still being offered internationally is artificial lift in Ecuador and the Middle East.

Figure 263: Revenue mix



Source: Company reports, Deutsche Bank

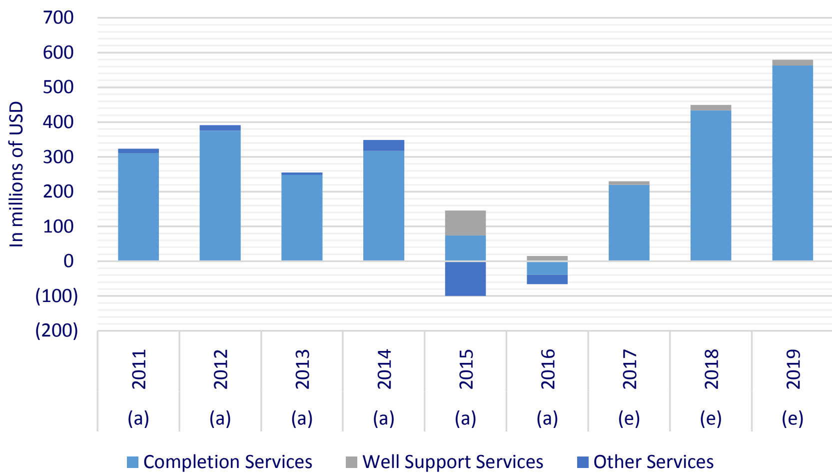
CJ wants to be positioned as a top 5 player in each of its key product lines and maintains a large footprint across the major US basins. The majority of Adjusted EBITDA is being generated by Completion Services (frac, wireline, pumping, cementing, and coiled tubing) with its assets generally concentrated in the Permian, Bakken, and Marcellus.

Figure 264: Year-end 2016 geographic foot print

	Completion Services					Well Support Services	
	Frac ('000hp)	Wireline trucks	Pumping units	Cement units	CT units	W/O rigs	Fluid trucks
Permian	290	39	19	20	7	125	255
Bakken	200	18	11	0	0	73	81
Marcellus	170	24	0	16	2	9	62
South TX	80	9	17	0	16	32	212
Mid-Con	40	10	10	0	0	0	0
Canada	0	0	0	0	0	75	0
Other	40	27	0	0	19	145	511
Total	**820**	**127**	**57**	**36**	**44**	**459**	**1,121**

Source: Company reports, Deutsche Bank

Figure 265: Segment EBITDA



Source: Company reports, Deutsche Bank

The primary contributors of free cash flow is its Completion Services segment. This business tends to benefit from greater leverage and pricing than the Well Support Services business. When CJ acquired the completion and production services business from NBR in 2015, the company greatly increased its exposure to production related spend in order to improve diversification, extend its portfolio across the well lifecycle, and access opex related customer spend. Despite improving activity levels, many of its Production Services businesses remain highly competitive on price due to overcapacity and still low levels of utilization. We do not believe this will remain a core part of CJ's product offering.

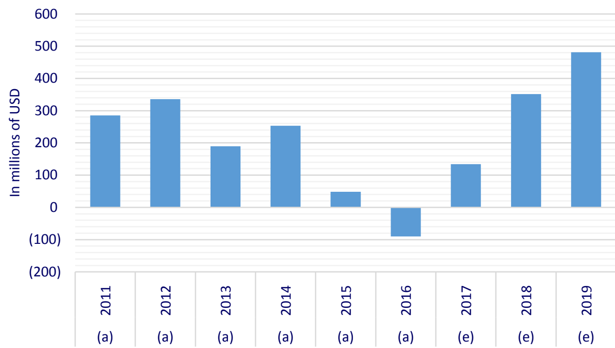
The primary uses of working capital and capex is to fund reactivation of completion related assets that were stacked during the downturn and crew up the equipment. CJ estimates reactivation costs of warm stacked pressure pumping hp in the range of $6-7mm per fleet while cold stacked equipment will be closer to $10-12mm per fleet. The company also ordered 20 newbuild pumps to be deployed in 2H17. Management plans to take a measured approach to reactivation of equipment driven by returns. CJ has also focused on improving its Production Services business by closing underperforming areas (e.g. coiled tubing in East TX) and redeploying those assets to more active regions and re-purposing underutilized fluid trucks to haul sand to help with last mile logistics.

DSOs temporarily spiked in Q1 as CJ migrated to a single ERP system at the beginning of the year. Management has said that it has started to improve by the end of Q1.

Balance Sheet and Liquidity

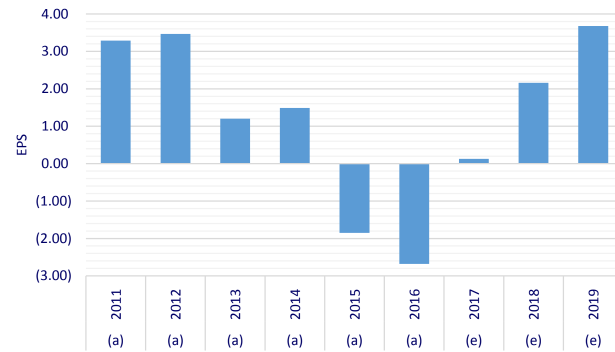
CJ increased its liquidity after emerging from Chapter 11 to about $426 million as of June 30, 2017. CJ eliminated $1.4 billion of debt from its Chapter 11 filing, which in turn removed close to $80mm of annual interest expense. On May 4, the company doubled their ABL revolver to $200mm from $100mm and removed the covenant that limited their ability to incur growth capex. With CJ being debt free (excluding letters of credit) and the removal of the covenant that limited their growth capex, the company can now fund reactivation of stacked equipment and order new build capacity based on returns rather than debt service.

Figure 266: Consolidated EBITDA



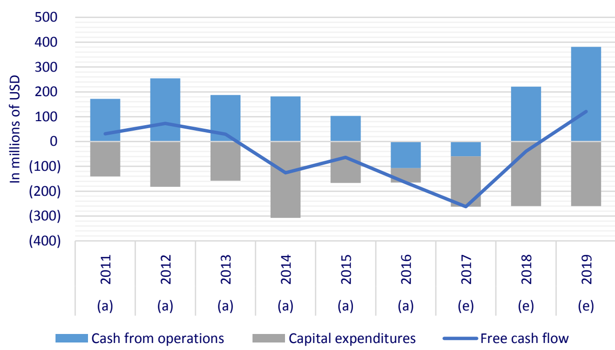
Source: Company reports, Deutsche Bank

Figure 267: Earnings per share



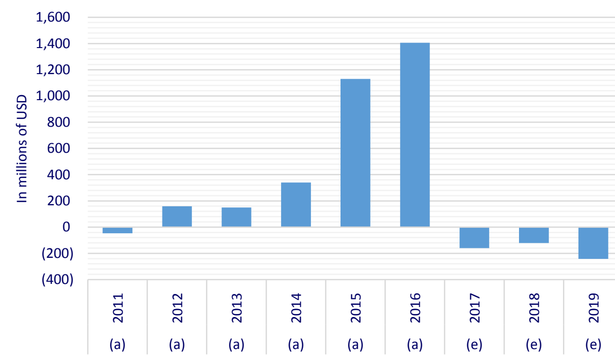
Source: Company reports, Deutsche Bank

Figure 268: Free cash flow and capex



Source: Company reports, Deutsche Bank

Figure 269: Net debt



Source: Company reports, Deutsche Bank

Figure 270: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:									
Completion Services	736	1,070	1,062	1,596	1,217	592	1,267	1,870	2,207
Well Support Services	0	0	0	0	456	362	394	401	418
Other Services	22	41	8	12	76	16	0	0	0
Total revenues	758	1,112	1,070	1,608	1,749	971	1,661	2,271	2,625
Segment EBITDA:									
Completion Services	310	376	248	317	74	(39)	220	434	563
Well Support Services	0	0	0	0	72	15	10	16	17
Other Services	13	16	7	31	(99)	(26)	0	0	0
Corporate and other	(38)	(55)	(65)	(96)	2	(40)	(95)	(98)	(98)
Total EBITDA	285	336	189	253	48	(90)	134	351	481
D&A	23	47	75	108	276	217	134	158	180
EBIT	262	289	115	145	(228)	(308)	0	193	301
Interest (expense)	(4)	(5)	(7)	(10)	(82)	(157)	(2)	(2)	(2)
Interest income	0	0	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	0	0	0	0
Other income	(0)	(1)	(0)	1	9	13	16	8	39
PBT	258	283	108	136	(301)	(452)	14	199	339
Income tax (expense)	(91)	(96)	(41)	(51)	111	135	(7)	(65)	(110)
Non-controlling interest	0	0	0	0	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0
Net income (operating)	167	187	66	84	(190)	(317)	8	134	229
Discontinued ops	0	0	0	0	0	0	0	0	0
Unusual after-tax	(5)	(5)	0	(15)	(683)	(627)	(26)	0	0
Net income (GAAP)	**162**	**182**	**66**	**69**	**(873)**	**(944)**	**(19)**	**134**	**229**
Operating EPS	**3.29**	**3.47**	**1.20**	**1.49**	**(1.85)**	**(2.68)**	**0.13**	**2.16**	**3.68**
GAAP EPS	3.19	3.38	1.20	1.22	(8.50)	(7.98)	(0.31)	2.16	3.68
DPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diluted shares	51	54	55	57	103	118	61	62	62
EBITDA margin	37.6%	30.2%	17.7%	15.7%	2.8%	-9.3%	8.1%	15.5%	18.3%
EBIT margin	34.6%	26.0%	10.7%	9.0%	-13.0%	-31.7%	0.0%	8.5%	11.5%
Tax rate	35.3%	33.9%	38.4%	37.9%	36.9%	29.9%	46.9%	32.5%	32.5%

Source: Deutsche Bank

Figure 271: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	167	187	66	84	(190)	(317)	8	134	229
Depreciation	23	47	75	108	276	217	134	158	180
Deferred tax	46	16	17	33	(273)	(130)	0	0	0
Chg in receivables	(72)	(11)	15	(136)	278	137	(235)	(91)	(34)
Chg in inventories	(29)	(11)	(10)	(50)	21	4	(19)	(14)	(4)
Chg in payables	41	(0)	18	132	(169)	(75)	52	28	8
Other	(4)	27	7	10	159	55	1	6	2
Cash from operations	172	255	187	182	103	(107)	(60)	221	381
Capital expenditures	(141)	(182)	(158)	(308)	(166)	(58)	(203)	(260)	(260)
Free cash flow	31	73	29	(126)	(63)	(165)	(262)	(39)	121
Acquisitions	(27)	(273)	(15)	(34)	(663)	(1)	0	0	0
Asset sales	2	0	1	1	4	33	31	0	0
Dividends paid	0	0	0	0	0	0	0	0	0
ESPP | options	0	3	5	1	0	0	0	0	0
Equity issuance, net	112	0	0	0	0	0	216	0	0
Debt issuance, net	(72)	170	(21)	165	796	181	0	0	0
Other	5	(4)	(0)	(12)	(58)	(9)	110	0	0
Chg in cash	52	(32)	(0)	(4)	16	39	95	(39)	121
FCF per share	0.61	1.34	0.53	(2.23)	(0.62)	(1.40)	(4.33)	(0.63)	1.94
Capex / revenue	0.19	0.16	0.15	0.19	0.10	0.06	0.12	0.11	0.10
Capex / depreciation	6.14	3.88	2.11	2.84	0.60	0.27	1.51	1.64	1.45

Source: Deutsche Bank

Figure 272: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	47	14	14	10	26	65	160	121	242
Accounts receivable	122	167	153	291	275	137	370	461	495
Inventories	45	61	71	122	102	54	69	83	88
Other current assets	10	8	19	38	82	44	57	71	76
Total current assets	224	250	257	461	484	300	656	736	901
Net PP&E	214	434	536	783	1,210	951	649	751	831
Goodwill	65	197	206	220	308	0	0	0	0
Other assets	35	132	134	149	230	111	111	125	130
Total assets	538	1,013	1,132	1,613	2,233	1,362	1,416	1,612	1,862
Accounts payable	58	70	89	229	213	74	136	164	172
Current debt	0	0	0	0	13	25	0	0	0
Other current liabilities	16	35	37	56	64	81	109	135	145
Total current liabilities	74	105	125	285	291	181	245	299	317
Long-term debt	0	174	164	350	1,142	1,445	0	0	0
Other LT liabilities	137	239	272	481	458	215	278	339	360
Shareholders' equity	400	600	696	782	633	(299)	1,139	1,273	1,502
Total liabilities and equity	538	1,013	1,132	1,613	2,233	1,362	1,416	1,612	1,862
Total debt	0	174	164	350	1,156	1,470	0	0	0
Net debt	(47)	159	150	340	1,130	1,406	(160)	(121)	(242)
Debt/capital	0%	22%	19%	31%	65%	125%	0%	0%	0%
Debt/equity	0%	29%	24%	45%	183%	-492%	0%	0%	0%
Debt turns	**0.0**	**0.5**	**0.9**	**1.4**	**23.8**	**(16.3)**	**0.0**	**0.0**	**0.0**

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Core Labs

Reuters	Bloomberg
CLB.N	CLB US

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Research Analyst
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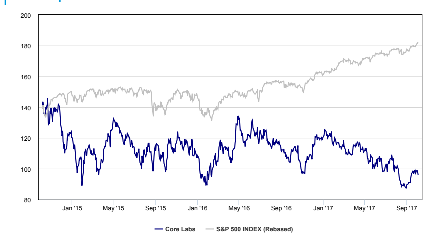
Price at 5 Oct 2017 (USD)	95.99
Price target	109.00
52-week range	125.37 - 87.47

Price/price relative



Performance (%)	1m	3m	12m
Absolute	7.2	-7.0	-13.5
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	4,258.8
Shares outstanding (m)	44.4
Free float (%)	–
Volume (5 Oct 2017)	87,496
Option volume (und. shrs., 1M avg.)	15,401

Source: Deutsche Bank

Best-in-Class Returns and Free Cash Flow

We are initiating coverage with a Buy rating and $109 price target

Core Labs is among the most disciplined operators in the oilfield services industry in our view, with an acute focus on returns, free cash flow, and returning capital to shareholders. The company also has good leverage to the US onshore margin expansion opportunity via its Production Enhancement business, which to-date has been impeded by the bottleneck in frac capacity. But as capacity is redeployed and added throughout 2H17 and into 2018, CLB's earnings power will get traction and its incremental margins should expand in to the 55-60% range.

Offering EOR techniques that might lift recoveries from 9% to 15%

Well probably somewhere in the middle near-term. CLB is involved in a study with a consortium of operators using its technology to increase the average unconventional oil recovery rate from 9% to something in the 12-15% range (conventional recoveries average closer to 40% to put into context). CLB's value proposition for a 1 mmbbl EUR well is another 300-500 mbbls on top of that, which in CLB's view could lift well returns by 40-50% including the added investment of $1-2 million. Too early to decipher the market size and pace of adoption, but increasing reservoir recovery is the Holy Grail for the oil industry.

Best-in-class free cash flow and shareholder returns

Returning excess capital to investors is a core philosophy of CLB's management team. CLB has been free cash positive every year over the last ten (and beyond) and its dividends have more than doubled to $2.20 per share since 2011 and have remained steady despite the severity of the downturn.

Valuation

Our $109 price target is 23x our estimate of the company's normalized EPS power of $4.75 per share, which is in-line with the 23x ten-year average multiple leading up to the 2014 collapse in oil prices. The stock is currently trading at 33x our 2018 EPS estimate of $2.92 and 26x our 2019 EPS estimate of $3.67.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) a continued rise in DUC inventories due to insufficient frac capacity.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.37	0.42A	0.57
2Q EPS	0.35	0.51A	0.66
3Q EPS	0.38	0.44	0.78
4Q EPS	0.41	0.52	0.91
FY EPS (USD)	1.51	1.90	2.92
P/E (x)	74.6	50.6	32.9
DPS (USD)	2.20	2.20	2.20
Dividend Yield (%)	2.0	2.3	2.3
Revenue (USDm)	594.7	650.3	723.1

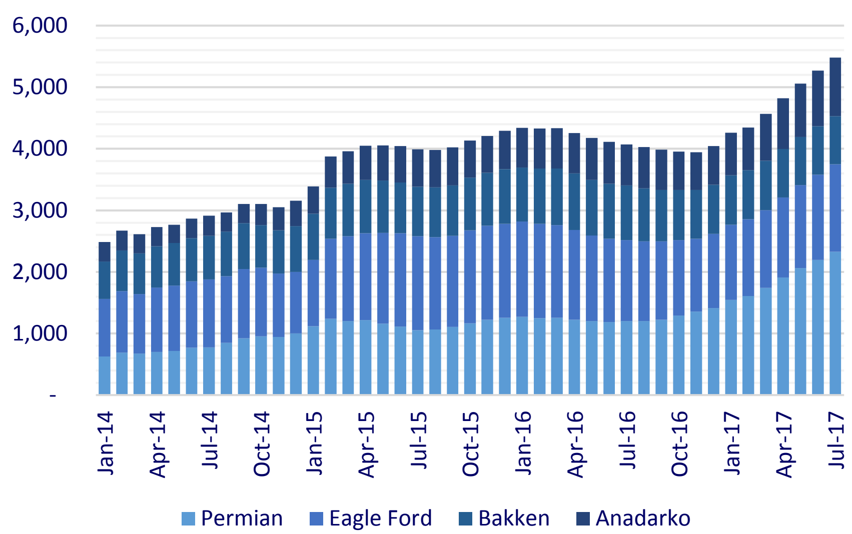
Source: Deutsche Bank estimates, company data

Key investment themes

Frac debottlenecking should enable earnings growth in 2018

CLB has not yet participated in the earnings recovery to the degree it can because of shortages in frac capacity triggering a build in DUC (drilled but uncompleted well) inventories. As frac capacity is redeployed and newbuilds begin coming to market, the rise in DUC inventories should be arrested by 2Q18 in our view, which should help CLB realize more of its onshore leverage. Its US revenues are correlated with completion and stimulation activity, not so much the raw rig count. Thus the build in DUCs since the recovery has impeded its earnings growth. Once activity is in full swing, CLB is guiding to an incremental margin of 60% initially, then back to its 35-45% range.

Figure 273: Drilled but uncompleted wells (DUCs)



Source: EIA

Larger pads, longer revenue recognition

A high-class problem, but nonetheless keeping earnings revisions low in 2017. The larger pads keep CLB on location longer versus the customary one well, one diagnostic, and then payment. Multi-well pads add to the project size and complexity, which is dragging out the revenue recognition for CLB. This should all catch up by early 2018 and begin flowing through just as frac is also beginning to debottleneck.

CLB technologies enabling leading edge lateral lengths to increase

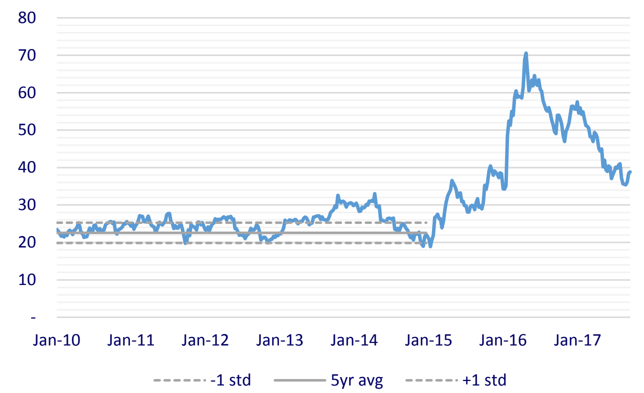
There has been a debate on how long can laterals extend, which is critical for service intensity. Beyond 10,000-ft, longer laterals encounter frictional forces that make the pumping of fluid and proppant in the wellbore less effective in terms of pressure at the toe of the well. CLB has developed friction reducers to enable longer laterals.

Valuation and risks

Our $109 price target is 23x our estimate of the company's normalized EPS power of $4.75 per share, which is in-line with the 23x ten-year average multiple leading up to the 2014 collapse in oil prices. The stock is currently trading at 33x our 2018 EPS estimate of $2.92 and 26x our 2019 EPS estimate of $3.67.

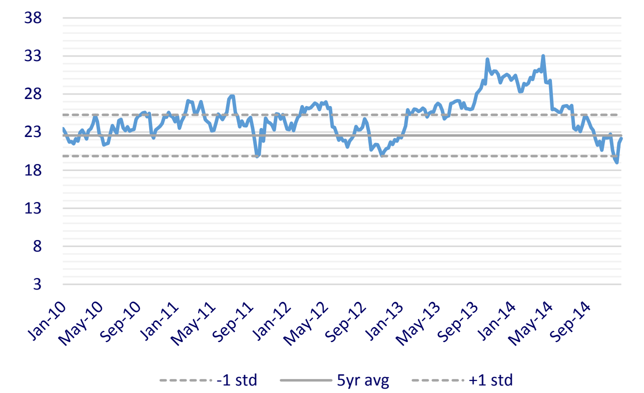
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) a continued rise in DUC inventories due to insufficient frac capacity.

Figure 274: The P/E valuation band as blown out



Source: Factset

Figure 275: The 5yr P/E leading up to 2014



Source: Factset

Company description

Core Laboratories (CLB) focuses on maximizing daily production and ultimate recovery rates for operators around the world. The company has two reporting segments, Reservoir Description and Production Enhancement. Reservoir Description provides analytical and field services that characterize the porous reservoir rock and all three reservoir fluids (natural gas, crude oil and water). It measures the quality and quantity of the fluids as well as that of the derived products. This data is used to determine the most efficient method of recovering, processing and refining the hydrocarbons. CLB analyzes reservoir rocks for their porosity, which determines the reservoir storage capacity, as well as permeability, which defines the ability of fluids to flow through the rock. These measurements are used to determine the oil and gas in-place and the rate at which it can be produced.

Figure 276: Operating divisions

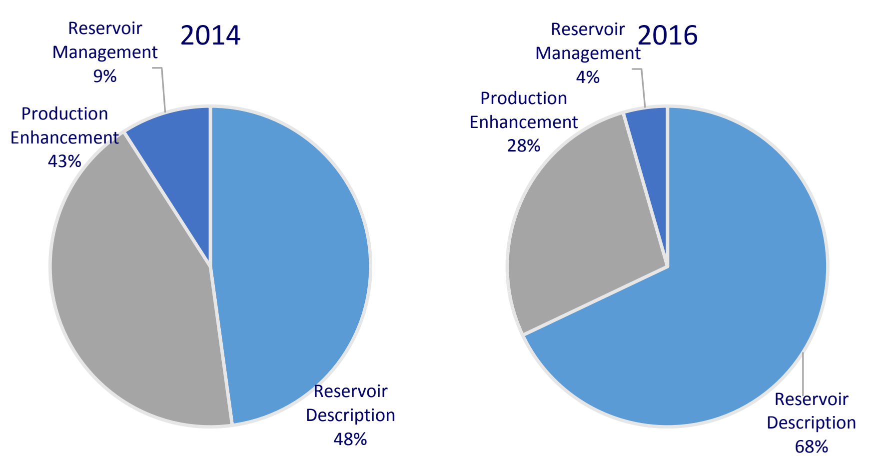
CORE LABS

Reservoir Description	Production Enhancement
- Reservoir fluid analysis	- Completion diagnostics
- Petrophysical services	- Reservoir diagnostics
- Equipment manufacturing	- Drilling diagnostics
- Digital rock characterization	- Perforating systems
	- Well monitoring systems
	- Completion and stimulation design

Source: Company reports

Production Enhancement provides products and services for well completions, perforations, stimulations and production. It evaluate the effectiveness of well completions and develops solutions to increase the effectiveness of enhanced oil recovery projects. It provides data on the rock type and strength which is then used to determine the proper design of the frac job.

Figure 277: Revenue mix



Source: Company reports, Deutsche Bank

Principal Sources and Uses of Cash Flow

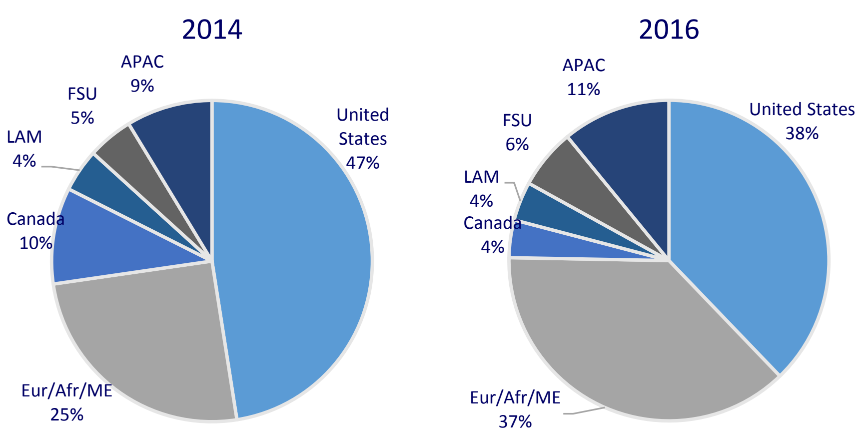
A mix of steady state and higher US onshore leverage

The Reservoir Description business is a steadier state revenue and EBITDA stream than Production Enhancement is. Management describes it as a $100 million per quarter baseline business that now stands to benefit from a recovery in international FIDs, which is progressing slowly, but with an early 2018 impact on earnings rather than 2H17. The company can generate anywhere from $2-5 million in revenue per project once FIDs move from the planning to the implementation phase.

CLB's Production Enhancement business has more leverage to the US onshore and international completion markets. Its US revenues, which company-wide were 38% of 2016 revenues, correlate not with the raw rig count, but with the actual completion and stimulation activity. Earlier earnings disappointments were triggered because while rig counts moved higher at a record pace, there was insufficient pressure pumping capacity to fulfill the completion needs of the producers, which contributed to the building of the DUC inventory. CLB makes money when wells are being completed, not inventoried. Frac capacity is coming online with a de-bottlenecking likely in 1H18.

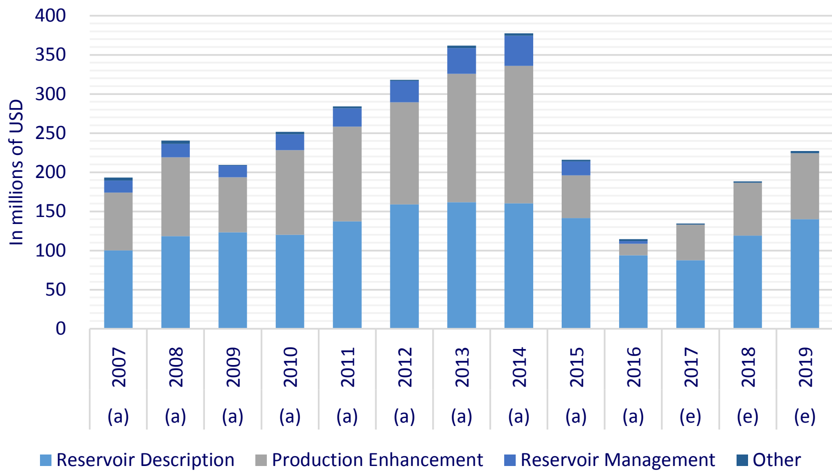
To put the leverage into context, Production Enhancement EBITDA grew 63% from 2010 to 2014, twice the pace of Reservoir Description. While some of this was driven by the company's niche technology M&A strategy, the majority was a function of the US onshore completions leverage.

Figure 278: Geographic revenues



Source: Company reports, Deutsche Bank

Figure 279: Segment EBITDA

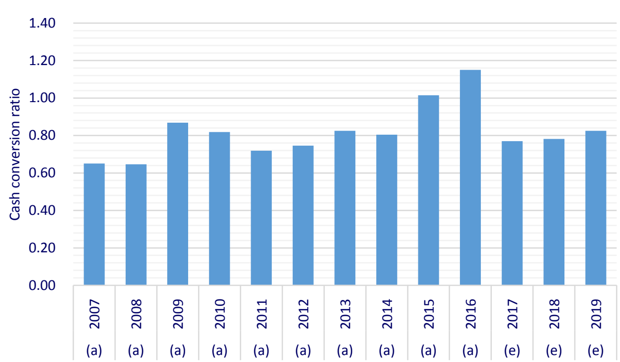


Note: Reservoir Management was folded into both Reservoir Description and Production Enhancement in 2017.
Source: Deutsche Bank

CLB demonstrates extraordinary positive free cash flow consistency

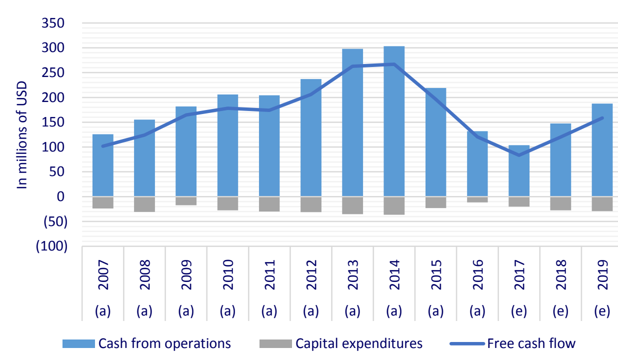
The company has generated close to $1.9 billion of free cash flow since 2007 with a very steady cash conversion performance. The capital intensity of this business is low. CLB has spent on average only 13% of its cash from operations on capital expenditures over the last ten years versus an integrated service company with high exposure to the frac industry, like Halliburton, which spent over 70% of its cash flow from operations on capital expenditures.

Figure 280: Leader in consistent cash conversion



Note: Measured as cash from operations/EBITDA
Source: Deutsche Bank

Figure 281: Positive free cash flow each year

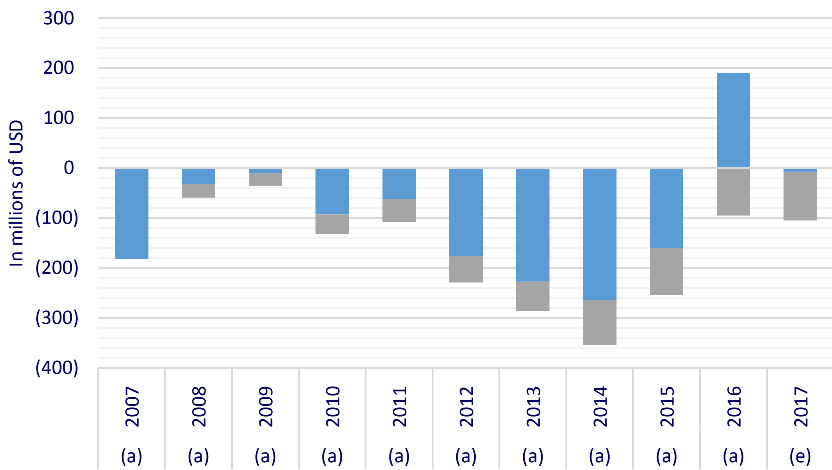


Source: Company reports, Deutsche Bank

Dividends and share buybacks are core uses of capital

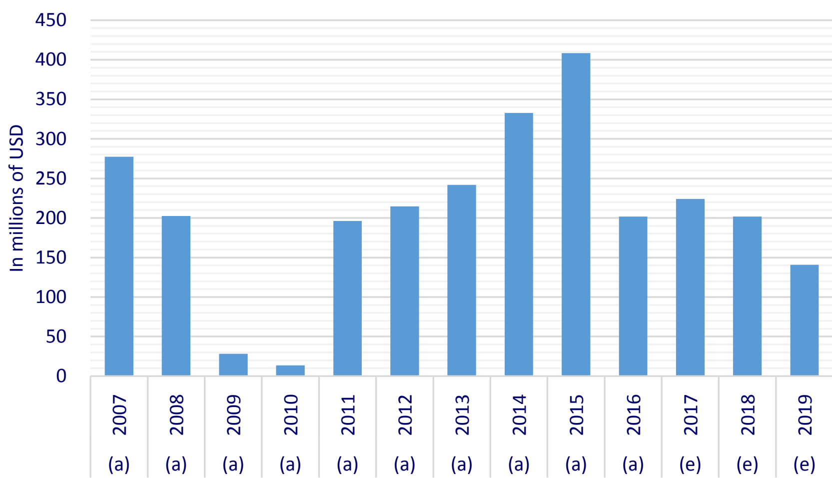
Since the inception of the share repurchase program in 2002, CLB has bought shares at an average price of $41.30 and has returned $2.4 billion in share repurchase and dividends.

Figure 282: Share repurchases and dividends paid



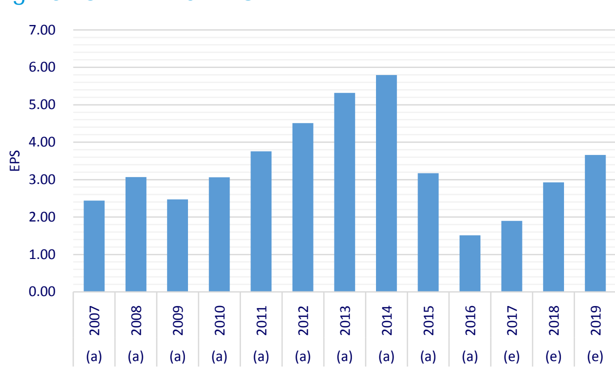
Source: Company reports, Deutsche Bank

Figure 283: Net debt



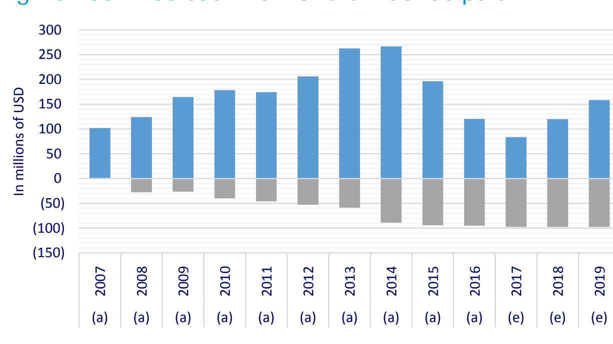
Source: Company reports, Deutsche Bank

Figure 284: Annual EPS



Source: Company reports, Deutsche Bank

Figure 285: Free cash flow and dividends paid



Source: Company reports, Deutsche Bank

Figure 286: Income Statement

In millions of USD	2009 (a)	2010 (a)	2011 (a)	2012 (a)	2013 (a)	2014 (a)	2015 (a)	2016 (a)	2017 (e)	2018 (e)	2019 (e)
Segment revenues:											
Reservoir Description	415	426	470	496	522	519	473	404	414	454	477
Production Enhancement	231	314	371	404	452	468	267	164	236	269	296
Reservoir Management	50	55	66	82	99	99	57	27	-	-	-
Total revenues	696	795	908	981	1,074	1,085	798	595	650	723	772
Segment EBITDA:											
Reservoir Description	123	120	137	159	162	160	141	94	87	119	141
Production Enhancement	71	108	121	130	164	175	55	15	46	68	84
Reservoir Management	15	20	23	27	33	39	18	3	-	-	-
Other	1	3	2	2	3	3	2	3	2	2	3
Total EBITDA	209	252	284	318	362	377	216	115	135	188	228
Segment D&A:											
Reservoir Description	14	14	14	14	15	16	17	18	18	18	17
Production Enhancement	6	6	6	6	8	8	7	5	5	5	5
Reservoir Management	1	1	1	1	1	1	2	1	-	-	-
Corporate and other	3	2	2	2	2	2	2	3	2	2	3
Total D&A	24	23	23	23	25	27	27	27	25	25	25
Segment EBIT:											
Reservoir Description	109	106	123	145	147	145	125	76	69	101	123
Production Enhancement	65	101	115	124	156	168	48	10	40	62	79
Reservoir Management	14	20	23	26	32	37	16	2	-	-	-
Corporate and other	(2)	1	0	(0)	1	1	(0)	0	(0)	(0)	(0)
EBIT	186	228	261	295	336	351	189	88	110	163	203
Interest (expense)	(16)	(16)	(11)	(9)	(9)	(11)	(12)	(12)	(11)	(11)	(11)
Interest income	-	-	-	-	-	-	-	-	-	-	-
Equity income	-	-	-	-	-	-	-	-	-	-	-
Other income	-	(1)	(0)	-	-	-	-	-	-	-	-
PBT	170	212	250	286	327	340	176	76	99	152	192
Income tax (expense)	(54)	(64)	(68)	(71)	(82)	(81)	(40)	(10)	(15)	(23)	(29)
Non-controlling interest	(0)	(0)	0	(1)	(0)	(1)	(0)	0	(0)	(0)	(0)
Preferred dividends	-	-	-	-	-	-	-	-	-	-	-
Net income (operating)	115	148	182	214	245	258	136	66	84	130	163
Discontinued ops	-	-	-	-	-	-	-	-	-	-	-
Unusual after-tax	(2)	(3)	3	2	(2)	(1)	(21)	(2)	(1)	-	-
Net income (GAAP)	**114**	**145**	**185**	**216**	**243**	**257**	**115**	**64**	**83**	**130**	**163**
Operating EPS	**2.47**	**3.06**	**3.76**	**4.51**	**5.32**	**5.79**	**3.17**	**1.51**	**1.90**	**2.92**	**3.67**
GAAP EPS	2.44	3.00	3.82	4.55	5.28	5.77	2.68	1.46	1.87	2.92	3.67
DPS	0.58	0.89	1.00	1.12	1.28	2.00	2.20	2.20	2.20	2.20	2.20
Diluted shares	47	48	48	48	46	45	43	44	44	44	44
EBITDA margin	30.1%	31.7%	31.3%	32.4%	33.7%	34.8%	27.1%	19.3%	20.7%	26.0%	29.5%
EBIT margin	26.7%	28.7%	28.7%	30.1%	31.3%	32.3%	23.6%	14.8%	16.8%	22.6%	26.2%
Tax rate	31.8%	30.0%	27.2%	25.0%	25.0%	23.7%	22.7%	13.4%	14.8%	15.0%	15.0%

Source: Deutsche Bank

Figure 287: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	115	148	182	214	245	258	136	66	84	130	162
Depreciation	24	23	23	23	25	27	27	27	25	25	25
Deferred tax	26	(10)	(7)	4	7	5	(0)	(14)	7	-	-
Chg in receivables	10	(22)	(12)	(17)	(16)	3	49	32	(17)	(18)	(1)
Chg in inventories	2	(2)	(16)	3	1	3	3	6	(3)	(1)	(0)
Chg in payables	(9)	12	12	(4)	(6)	(3)	(13)	(1)	10	1	0
Other	14	58	22	13	43	10	17	17	(2)	10	0
Cash from operations	182	206	204	237	298	303	219	132	104	147	187
Capital expenditures	(17)	(28)	(30)	(31)	(35)	(37)	(23)	(11)	(20)	(27)	(29)
Free cash flow	165	178	174	206	263	267	196	121	83	120	158
Acquisitions	-	(9)	(21)	(1)	-	(1)	(14)	(1)	-	-	-
Asset sales	1	1	1	1	1	1	1	1	1	-	-
Dividends paid	(26)	(40)	(46)	(53)	(59)	(89)	(94)	(95)	(97)	(98)	(98)
ESPP | options	0	0	0	0	0	-	-	-	-	-	-
Equity issuance, net	(9)	(92)	(62)	(176)	(227)	(264)	(160)	190	(7)	-	-
Debt issuance, net	-	(82)	69	9	33	89	75	(217)	17	-	-
Other	15	(3)	(220)	4	(5)	(4)	(6)	(5)	(1)	-	-
Chg in cash	145	(47)	(105)	(10)	6	(2)	(1)	(8)	(5)	22	61
FCF per share	3.53	3.70	3.60	4.34	5.71	5.98	4.58	2.76	1.88	2.70	3.57
Capex / revenue	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.03	0.04	0.04
Capex / depreciation	0.73	1.19	1.28	1.36	1.39	1.37	0.83	0.42	0.81	1.11	1.15

Source: Deutsche Bank

Figure 288: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	181	134	29	19	25	23	22	15	10	32	93
Accounts receivable	134	155	171	185	201	197	146	114	131	149	150
Inventories	32	34	53	49	47	43	41	34	37	37	37
Other current assets	44	27	27	44	31	38	29	24	28	32	32
Total current assets	391	349	281	297	304	302	239	186	206	250	312
Net PP&E	99	104	115	125	139	149	143	130	124	127	131
Goodwill	149	154	163	163	163	164	178	179	179	179	179
Other assets	20	28	46	51	55	60	65	78	74	81	81
Total assets	658	636	605	637	661	676	625	573	583	637	703
Accounts payable	33	45	58	55	51	47	33	34	43	44	44
Current debt	-	148	2	-	-	-	-	-	-	-	-
Other current liabilities	73	88	77	85	85	85	87	70	61	69	69
Total current liabilities	106	280	137	141	136	132	121	104	104	113	113
Long-term debt	209	-	223	234	267	356	431	216	234	234	234
Other LT liabilities	63	67	67	80	95	100	103	101	100	113	114
Shareholders' equity	279	289	178	182	163	88	(29)	151	145	178	242
Total liabilities and equity	658	636	605	637	661	676	625	573	583	637	703
Total debt	209	148	225	234	267	356	431	216	234	234	234
Net debt	28	14	196	215	242	333	408	202	224	202	141
Debt/capital	43%	34%	56%	56%	62%	80%	107%	59%	62%	57%	49%
Debt/equity	75%	51%	127%	128%	163%	407%	(1483%)	143%	161%	131%	96%
Debt turns	**1.0**	**0.6**	**0.8**	**0.7**	**0.7**	**0.9**	**2.0**	**1.9**	**1.7**	**1.2**	**1.0**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Diamond Offshore Drilling

Reuters	Bloomberg
DO.N	DO US

David Havens
Research Analyst
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Price at 5 Oct 2017 (USD)	14.88
Price target	15.00
52-week range	21.08 - 10.22

Looking to replenish earnings power

Initiating coverage with a Hold rating and an $15 price target

Diamond's earnings power has diminished severely, but its fiscal stability compares very favorably with its peers. The company has no more newbuild obligations to burden free cash flow, dividends have already been eliminated, and its early termination risk has run its course in our view. But we expect the deepwater market to remain challenged through at least 2019 with a recovery forming in 2017, but one that is very slow to build and one with fierce pricing tactics. While we believe the alpha short is gone, the weakening near-term trends in EBITDA leaves little upside without a rapid move higher in oil prices.

Severely diminished earnings power

Diamond has been experiencing eroding earnings power since 2009. Prior to the drop in oil prices, EBITDA had already been halved from the high of $2.3 billion, and we expect it will fall to about $0.36 billion in 2019. Its fleet is also half of its peak earnings size with its midwater floating fleet almost entirely gone due largely to scrapping. We believe its core marketable fleet has consolidated around 11 of its remaining 19 rigs including the four newbuild "Blackships" which are 55% of its backlog. Diamond has been among the most aggressive scrappers of rigs, and we expect management will look to replenish its earnings power via M&A in the coming months and years.

Peer leading fiscal stability

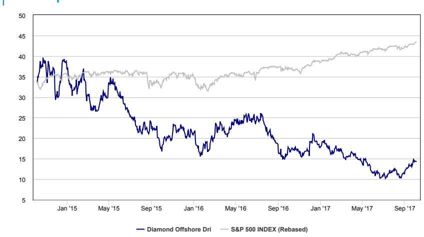
Despite the erosion in earnings power and the severity of the deepwater downturn, Diamond has managed to keep a relatively high fiscal stability with debt turns of 3.2x versus its peers as high as 8.0x. Its $1.5 billion credit facility is untouched and its nearest debt maturity is May 2019 for $500 million, which the company is more than equipped to handle.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.64	0.17A	-0.03
2Q EPS	0.16	0.45A	0.11
3Q EPS	0.10	0.19	0.15
4Q EPS	0.27	0.13	-0.07
FY EPS (USD)	1.17	0.95	0.16
OLD FY EPS (USD)	1.23	0.87	0.35
% Change	-5.1%	9.5%	-54.9%
P/E (x)	17.3	15.7	93.7
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	1,564.7	1,465.0	1,283.7

Source: Deutsche Bank estimates, company data

Price/price relative



Performance (%)	1m	3m	12m
Absolute	20.0	26.2	-12.8
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	2,042.0
Shares outstanding (m)	137.2
Free float (%)	100
Volume (5 Oct 2017)	564,897
Option volume (und. shrs., 1M avg.)	93,916

Source: Deutsche Bank

Valuation

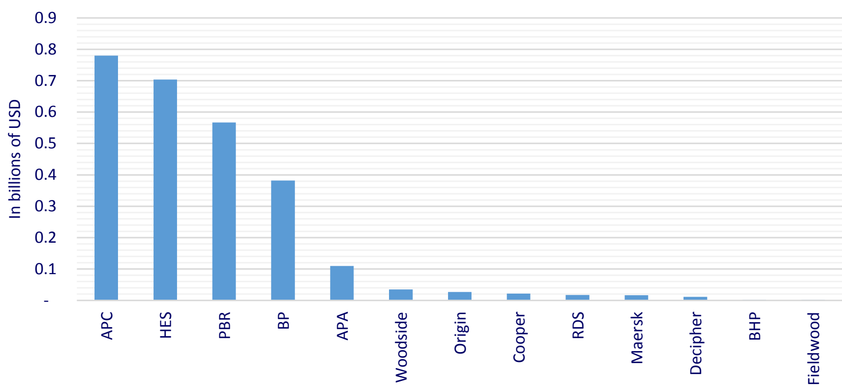
We are initiating coverage with an $15 price target. This is 5.2x our estimate of the company's normalized EBITDA of $0.64 billion, which is one-turn below the 6.2x ten-year average multiple. The company is currently trading at 7.1x our fiscal 2018 EBITDA estimate of $0.46 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

Key investment themes

Ultra-deepwater contracts providing some cover through 2019

These are the most challenging market conditions the deepwater industry has ever faced. Diamond's sources of cash flow have diminished severely and its marketed fleet has been halved due largely to rig attrition. The company's backlog of $2.7 billion is down 75% from the $10.9 billion in February 2009. But Diamond secured some cover with its four newbuild drillships, which are 55% of the current backlog. Higher legacy contracts with Anadarko (2) and Hess (2) at $495 kpd and $400 kpd respectively with durations extending to mid-June 2019 and early 2020 provide the company well needed cash flow.

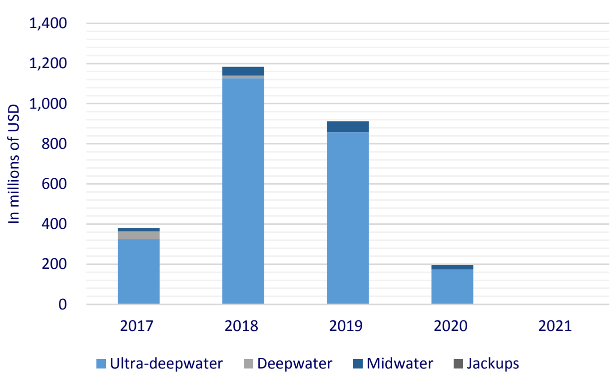
Figure 289: Backlog by customer



Source: Company reports, Deutsche Bank

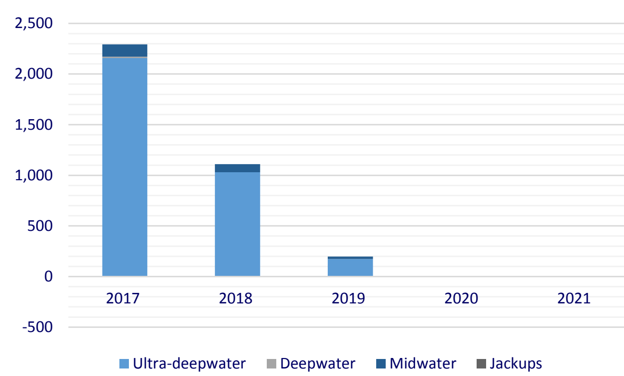
Diamond's top five customers represent 95% of the company's total backlog. The ultra-deepwater is 93% of the total backlog.

Figure 290: Revenues in backlog



Source: Company reports, Deutsche Bank

Figure 291: Year-end backlog



Source: Company reports, Deutsche Bank

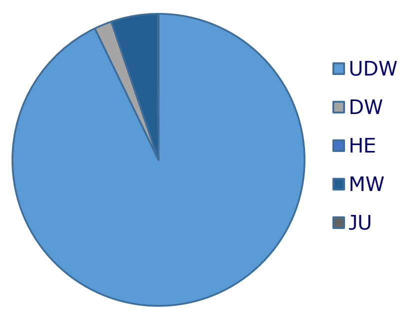
Figure 292: Diamond Offshore backlog details

Revenue in backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	325	1,127	858	174	0
Deepwater	38	13	0	0	0
Harsh-environment	0	0	0	0	0
Midwater	17	43	55	23	0
Jackups	2	0	0	0	0
Total backlog	**383**	**1,184**	**913**	**196**	**0**

Total backlog	Abbrev	($bn)
Ultra-deepwater	UDW	2.5
Deepwater	DW	0.1
Harsh-environment	HE	
Midwater	MW	0.1
Jackups	JU	0.0
Total backlog		**2.7**

Days committed	2017	2018	2019	2020	2021
Ultra-deepwater	65%	69%	50%	10%	0%
Deepwater	40%	4%	0%	0%	0%
Harsh-environment					
Midwater	21%	42%	50%	21%	0%
Jackups	26%	0%	0%	0%	0%
Total backlog	**52%**	**45%**	**34%**	**8%**	**0%**

Backlog by rig type



Year-end backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	2,158	1,031	174	0	0
Deepwater	13	0	0	0	0
Harsh-environment	0	0	0	0	0
Midwater	121	78	23	0	0
Jackups	0	0	0	0	0
Total backlog	**2,292**	**1,109**	**196**	**0**	**0**

	2017	**2018**	**2019**
Total debt	1,981	1,981	1,481
Debt / YE backlog	**0.9**	**1.8**	**7.5**

Backlog by customer ($m	#1	#2	#3	#4	#5
Ultra-deepwater	**APC**	**HES**	**PBR**	**BP**	**Origin**
Backlog	780	704	567	382	27
% of backlog	31%	28%	23%	15%	1%
Deepwater	**Woodside**	**Maersk**			
Backlog	35	16			
% of backlog	68%	32%			
Harsh-environment					
Backlog					
% of backlog					
Midwater	**APA**	**RDS**	**Decipher**		
Backlog	110	17	11		
% of backlog	79%	12%	8%		
Jackups	**Fieldwood**				
Backlog	2				
% of backlog	100%				

Top 5 customers in backlog		Percent	$bn
APC	#1	29%	0.8
HES	#2	26%	0.7
PBR	#3	21%	0.6
BP	#4	14%	0.4
APA	#5	4%	0.1
Other		**5%**	**0.1**

Fleet composition	2017	2018	2019
Ultra-deepwater	11	11	11
Deepwater	5	5	5
Harsh-environment	-	-	-
Midwater	2	2	2
Jackups	1	1	1
Total in fleet	**19**	**19**	**19**

Source: Company reports, Deutsche Bank

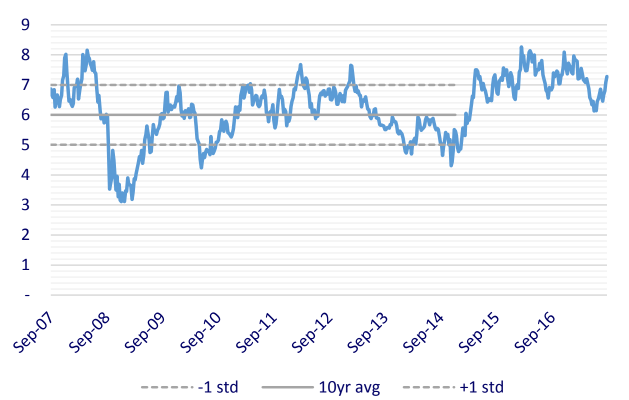
Valuation and risks

We are initiating coverage of Diamond Offshore with an $15 price target. This is 5.2x our estimate of the company's normalized EBITDA of $0.64 billion, which is one-turn below the 6.2x ten-year average multiple. The company is currently trading at 7.1x our fiscal 2018 EBITDA estimate of $0.46 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

In terms of steel value, we assess the trough net asset value at $6.50 per share, which assumes the market endures another three years of high volumes of cold-stacking once contracts expire and leading edge market rates that stay at breakeven levels ($160-170 kpd).

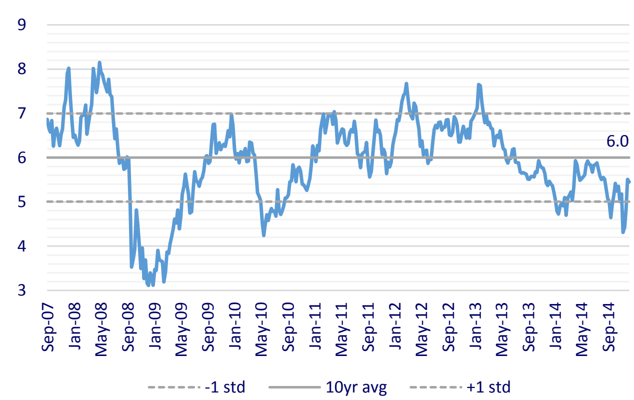
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) M&A with Diamond as the suitor, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Figure 293: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 294: The 5yr EV/EBITDA leading up to 2014

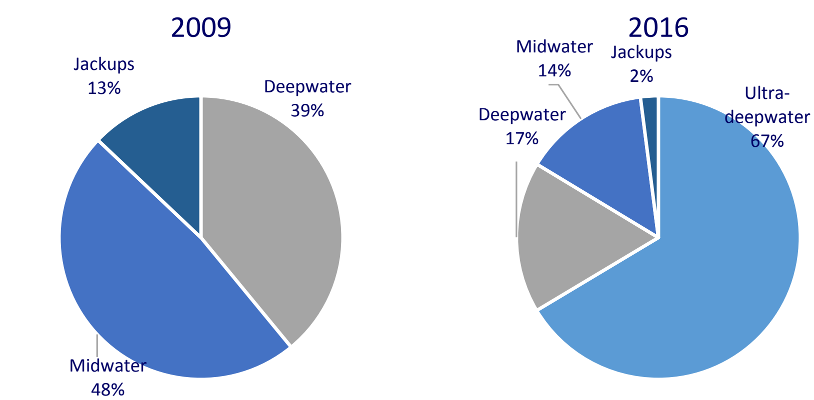


Source: Factset

Company description

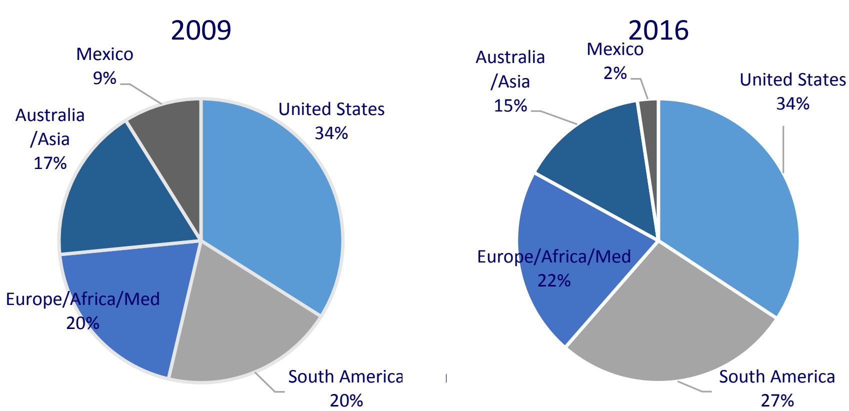
Diamond Offshore (DO) is a contract drilling company with a fleet of 19 mobile offshore drilling rigs including 11 ultra-deepwater floaters, five deepwater floaters, two midwater floaters and one jackup. It is a company that until recently preferred upgrading older rigs instead of funding newbuilds. Back in 2009, when Diamond recorded its highest EBITDA and free cash flow of $2.3 billion and $1.1 billion respectively, its fleet was twice its current size and its revenue mix was heavily weighted toward its midwater semisubmersibles. Most of these rigs have since been scrapped due to poor industry conditions and the company has pivoted its strategy to focus on leading edge ultra-deepwater rigs that are more suitable for what has become a fiercely competitive deepwater market.

Figure 295: Revenues by rig type



Source: Company reports, Deutsche Bank

Figure 296: Revenues by geography



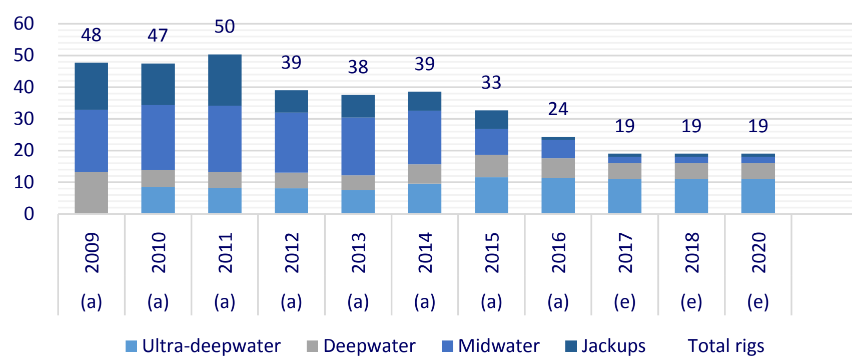
Source: Company reports

Principal Sources and Uses of Cash Flow

Ultra-deepwater has become Diamond's core source of cash flow

Diamond's principal source of cash flow is its ultra-deepwater fleet. Since 2009, the company has spent in excess of $4.1 billion to reposition its fleet in the ultra-deepwater and another $0.8 billion for two major deepwater upgrades. This segment generated almost two-thirds of its 2016 EBITDA of $0.7 billion and is 93% of the company's $2.7 billion backlog. Its four newbuild drillships, which cost over $2.5 billion to build, account for 55% of the total backlog at $1.5 billion. But even this segment is not immune to obsolescence. Three of the semis in this segment including the Ocean Confidence, Ocean Rover and Ocean Endeavor, were originally built in the 1970s and later upgraded extensively. These rigs are now cold-stacked and some, if not all are candidates for retirement in our view. The company recently retired the Ocean Baroness, which was the fourth such rig.

Figure 297: Change in fleet size and mix



Source: Company reports, Deutsche Bank

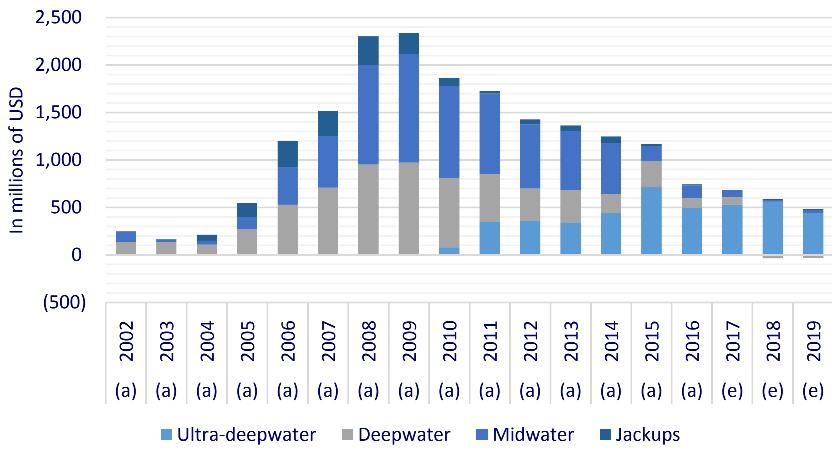
While the company has no remaining newbuild or upgrade obligations left, it does continue to seek ways to build scale in the ultra-deepwater. The company has vetted its Floating Factory concept, but we do not believe management intends to fund any more newbuilds under current industry conditions. We believe acquisitions are a part of Diamond's strategy to build scale.

Severely diminished earnings power

Diamond recorded its highest ever EBITDA and free cash flow of $2.3 billion and $1.1 billion respectively in 2009. Back then, the company had 47 offshore rigs, 19 of which were midwater floaters. These midwater floaters were $6 billion of the total $10.9 billion of backlog in February 2009, and generated 49% of the EBITDA. Diamond's fleet of midwater semisubmersibles has since been reduced to two, mainly due to attrition as well as a few upgrades. Midwater backlog stands at a mere $0.1 billion. The midwater fleet is essentially obsolete with no real value ascribed to it in our model.

Diamond's fleet of six deepwater semisubmersibles also struggles with obsolescence and has a backlog of only $0.1 billion. The company has one jackup left (down from 15 in 2009) that is strategic only in the sense that it provides a foothold in Mexico. Combine all this with dayrates that are likely to remain fiercely competitive into 2019 means restoring earnings power to 2009 levels of $2.3 billion is implausible, at least organically in our view.

Figure 298: Segment EBITDA



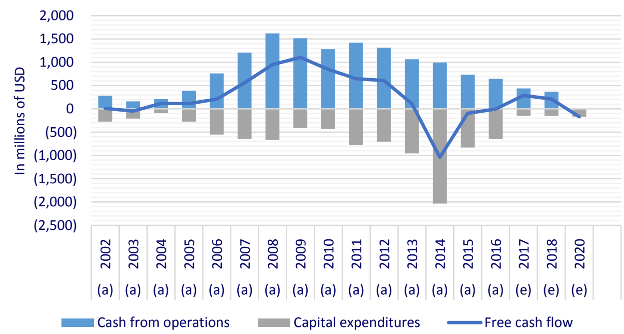
Source: Company reports, Deutsche Bank

While Diamond will seek to restore some of its lost earnings power via acquisitions in our view, the earnings power until then has been more than halved. We believe only 11 of its existing 19 rigs will be core cash flowing assets. Aggregated, we believe the earnings power of the fleet in terms of EBITDA is about $925 million compared to the $2.3 billion generated in 2009, and this assumes dayrates recover to NPV breakeven levels. We estimate the NPV breakeven level for a 12,000-ft dynamically positioned drillship is $425,000 per day, which is a lofty assumption in such a challenging market. If we use a leading edge rate recovery of $300,000 per day, which we believe is still challenging, but more reasonable through 2019, the earnings power is $640 million in our view.

Fleet renewal program is complete, burden on free cash flow lifted

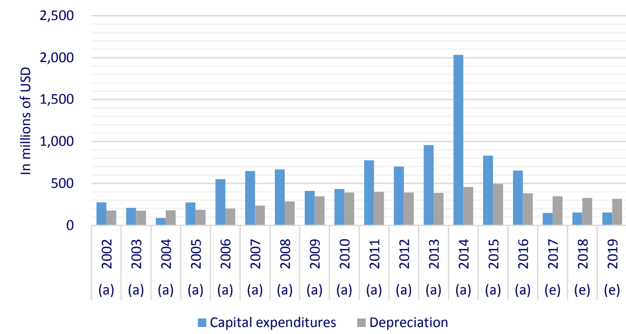
The principal uses of cash have been the fleet renewal program and dividends. Since 2007, Diamond's capital expenditures have totaled $8.1 billion, or 69% of cash from operations. The company's capex elevated in 2011 when it embarked on its five-rig ultra-deepwater newbuild program which accounted for about $4.1 billion of total expenditures, or 36% of the aggregate cash from operations. Its two major upgrades on the Ocean Onyx and Ocean Apex accounted for another $0.8 billion. Diamond completed its newbuild program in 2016 and has guided 2017 capex to $145 million, which is down over 90% from the peak of $2 billion in 2014.

Figure 299: Free cash flow and dividends



Source: Deutsche Bank

Figure 300: Capex

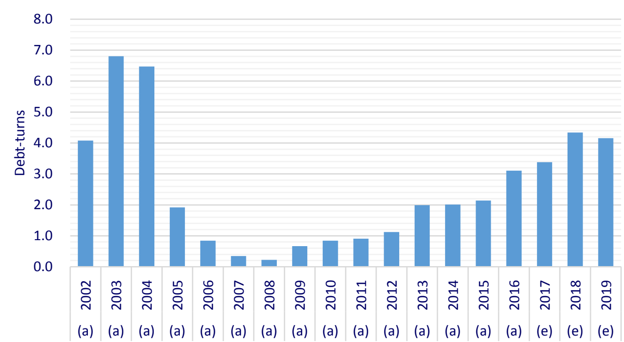


Source: Deutsche Bank

Elevated leverage, but metrics still compare favorably to peers

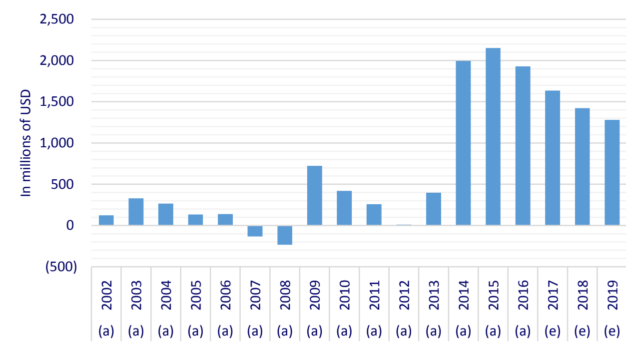
While Diamond's earnings power has diminished more than its peers, its fiscal stability is superior to most of its peers that are trending above 8x debt turns. The next debt maturity of $500 million for Diamond is not until May 2019.

Figure 301: Debt turns



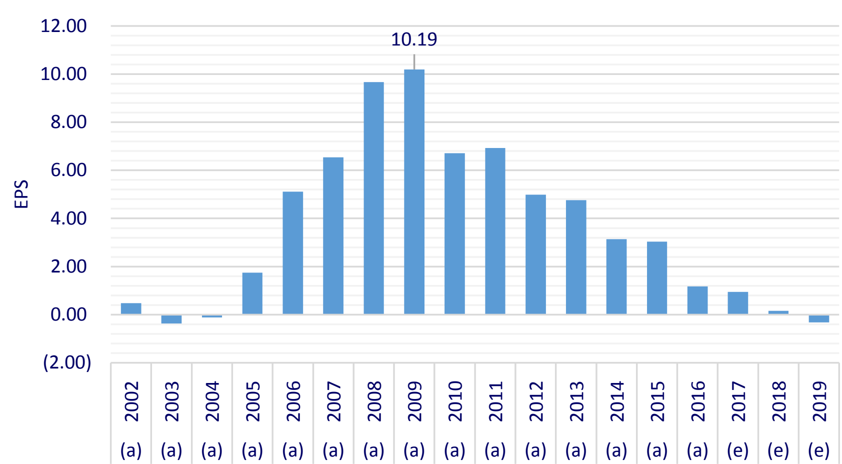
Source: Company reports, Deutsche Bank

Figure 302: Net debt



Source: Company reports, Deutsche Bank

Figure 303: EPS trend



Source: Company reports, Deutsche Bank

Figure 304: Fleet profile

Rig name	Water depth (ft)	Rig type	Year in service	Rig design	Backlog (yrs)	Backlog ($m)
Ultra-deepwater (11):						
Ocean Courage	10,000	6G SS-DP	2009	Friede & Goldman ExD	2.8	406.7
Ocean BlackHornet	12,000	DS-DP	2014	GustoMSC P10000	2.6	465.3
Ocean BlackLion	12,000	DS-DP	2015	GustoMSC P10000	2.4	352.0
Ocean BlackRhino	12,000	DS-DP	2014	GustoMSC P10000	2.4	352.0
Ocean GreatWhite	10,000	6G SS-DP	2016	Moss Maritime CS-60 E	2.3	382.1
Ocean BlackHawk	12,000	DS-DP	2014	GustoMSC P10000	1.7	314.3
Ocean Valor	10,000	6G SS-DP	2009	Friede & Goldman ExD	1.1	160.5
Ocean Monarch	10,000	5G SS	2008	ODECO Ocean Victory	1.2	50.4
Ocean Confidence	10,000	5G SS-DP	2001	Aker H-3.2 Enhanced	-	-
Ocean Endeavor	10,000	5G SS	2007	ODECO Ocean Victory	-	-
Ocean Rover	8,000	5G SS	2003	ODECO Ocean Victory	-	-
Deepwater (5):						
Ocean Apex	6,000	5G SS	2014	ODECO Ocean Victory	0.4	35.4
Ocean Valiant	5,500	4G SS	1988	ODECO Ocean Odyssey	0.4	16.3
Ocean Onyx	6,000	5G SS	2014	ODECO Ocean Victory	-	-
Ocean America	5,500	4G SS	1988	ODECO Ocean Odyssey	-	-
Ocean Victory	5,500	4G SS	1997	ODECO Ocean Victory	-	-
Midwater (2):						
Ocean Patriot	3,000	3G SS	1983	Trosvik Bingo 3000	2.7	127.0
Ocean Guardian	1,500	3G SS	1985	E&W/Sedco 711 Series	0.7	11.3
Jackups (1):						
Ocean Scepter	350	IC	2008	KFELS Super B Class	0.1	1.9

Source: Company reports, Deutsche Bank

Figure 305: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Ultra-deepwater	0	188	842	903	874	976	1,339	989	1,072	1,079	903
Deepwater	1,381	1,193	733	598	619	494	549	257	203	84	88
Midwater	1,699	1,581	1,482	1,275	1,222	1,073	388	213	136	68	93
Jackups	457	268	198	161	174	178	85	30	24	30	31
Reimbursables	95	93	68	50	77	78	59	75	30	23	20
Total revenue	3,631	3,323	3,322	2,987	2,965	2,800	2,419	1,565	1,465	1,284	1,135
Segment EBITDA:											
Ultra-deepwater	0	80	348	357	335	440	719	495	529	563	441
Deepwater	974	735	505	345	351	202	271	108	78	(37)	(33)
Midwater	1,141	966	847	673	618	538	157	129	75	15	33
Jackups	221	83	28	54	59	67	19	12	(2)	12	12
Other	(23)	(19)	(22)	(30)	(46)	(49)	(34)	(27)	(20)	(22)	(22)
Reimbursables	2	2	2	2	2	1	1	17	(0)	(2)	(3)
Corporate G&A	(63)	(67)	(65)	(65)	(65)	(82)	(66)	(64)	(72)	(72)	(72)
EBITDA	2,252	1,780	1,643	1,336	1,253	1,118	1,067	671	587	457	356
D&A	346	393	399	393	388	456	493	382	347	327	316
EBIT	1,905	1,387	1,244	943	865	662	574	289	240	130	40
Interest (expense)	(50)	(91)	(73)	(46)	(25)	(68)	(94)	(90)	(109)	(109)	(87)
Interest income	4	3	7	5	1	1	3	1	1	2	2
Gain (Loss) on Sales	0	1	5	1	0	(1)	(1)	(4)	1	0	0
Other income	10	2	(3)	(1)	(2)	2	0	(22)	1	0	0
PBT	1,870	1,303	1,179	902	840	595	483	174	134	22	(45)
Income tax (expense)	(452)	(369)	(217)	(208)	(178)	(164)	(66)	(13)	(4)	(1)	1
Non-controlling interest	0	0	0	0	0	0	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	1,418	934	963	694	662	431	416	161	130	22	(44)
Discontinued ops	0	0	0	0	0	0	0	0	0	0	0
Unusual after-tax	(42)	22	0	26	(115)	(44)	(691)	(577)	(46)	0	0
Net income (GAAP)	1,376	955	963	720	546	387	(274)	(416)	84	22	(44)
Operating EPS	**10.19**	**6.71**	**6.92**	**4.99**	**4.76**	**3.13**	**3.03**	**1.17**	**0.95**	**0.16**	**(0.32)**
GAAP EPS	9.89	6.87	6.92	5.18	3.93	2.81	(2.00)	(3.03)	0.61	0.16	(0.32)
DPS	8.00	5.25	3.50	3.50	3.50	3.50	0.50	0.00	0.00	0.00	0.00
Diluted shares	139	139	139	139	139	137	137	137	137	137	137
EBITDA margin	62.0%	53.6%	49.4%	44.7%	42.3%	39.9%	44.1%	42.9%	40.1%	35.6%	31.4%
Tax rate	24%	28%	18%	23%	21%	28%	14%	8%	3%	3%	3%
Utilization:											
Ultra-deepwater	n/a	70%	82%	85%	87%	65%	64%	51%	59%	67%	61%
Deepwater	79%	70%	94%	88%	86%	55%	52%	34%	43%	36%	39%
Midwater	85%	79%	72%	68%	66%	62%	36%	30%	33%	71%	97%
Jackups	66%	61%	46%	53%	76%	78%	42%	13%	68%	98%	97%
Dayrates ($000):											
Ultra-deepwater	n/a	341	343	355	330	435	498	477	429	399	366
Deepwater	380	380	416	369	395	402	410	305	233	126	125
Midwater	282	278	270	263	267	269	271	293	320	130	132
Jackups	126	88	82	90	88	96	93	202	76	84	86

Source: Deutsche Bank

Figure 306: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	1,418	934	963	694	662	431	416	161	130	22	(44)
Depreciation	346	393	399	393	388	456	493	382	347	327	316
Deferred tax	86	(7)	2	(51)	34	2	(242)	(106)	(54)	0	0
Chg in receivables	(220)	143	61	64	8	5	59	159	(11)	20	26
Chg in inventories	0	0	0	0	0	0	0	0	0	0	0
Chg in payables	(27)	33	(10)	10	47	27	(181)	(71)	(15)	1	(2)
Other	(87)	(214)	6	201	(73)	71	191	122	41	(1)	(1)
Cash from operations	1,517	1,282	1,420	1,311	1,066	993	736	647	438	369	295
Capital expenditures	(412)	(434)	(775)	(702)	(958)	(2,033)	(831)	(653)	(149)	(154)	(154)
Free cash flow	1,104	848	645	609	108	(1,040)	(94)	(6)	289	215	141
Acquisitions	(950)	0	0	0	0	0	0	0	0	0	0
Asset sales	40	188	6	138	5	18	13	222	4	0	0
Dividends paid	(1,115)	(734)	(490)	(490)	(490)	(486)	(69)	(0)	0	0	0
ESPP | options	1	0	0	0	0	0	0	0	0	0	0
Equity issuance, net	0	0	0	0	0	(88)	0	0	0	0	0
Debt issuance, net	996	0	0	0	988	(250)	37	(182)	(104)	0	(500)
Other	(36)	(3)	(1)	(8)	1	(2)	(5)	(7)	(0)	0	0
Chg in cash	41	299	159	249	611	(1,847)	(119)	26	188	215	(359)
FCF per share	7.94	6.10	4.64	4.38	0.78	(7.56)	(0.69)	(0.04)	2.10	1.56	1.03
Capex / revenue	0.11	0.13	0.23	0.24	0.32	0.73	0.34	0.42	0.10	0.12	0.14
Capex / depreciation	1.19	1.10	1.94	1.79	2.47	4.45	1.68	1.71	0.43	0.47	0.49

Source: Deutsche Bank

Figure 307: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	777	1,077	1,236	1,486	2,097	250	131	156	345	559	200
Accounts receivable	791	610	564	500	469	464	405	247	258	237	211
Inventories	0	0	0	0	0	0	0	0	0	0	0
Other current assets	155	177	193	148	152	186	134	103	90	83	74
Total current assets	1,723	1,863	1,993	2,133	2,718	899	670	506	692	880	485
Net PP&E	4,432	4,284	4,667	4,865	5,467	6,946	6,379	5,727	5,400	5,227	5,065
Goodwill	0	0	0	0	0	0	0	0	0	0	0
Other assets	109	580	304	237	206	176	116	139	103	95	84
Total assets	6,264	6,727	6,964	7,235	8,391	8,021	7,165	6,372	6,195	6,201	5,634
Accounts payable	75	99	64	97	94	138	70	30	30	31	28
Accrued expenses	302	469	336	324	371	427	254	182	93	85	76
Current debt	4	0	0	0	250	250	287	104	0	500	0
Other current liabilities	32	58	27	64	31	42	15	24	11	11	9
Total current liabilities	413	626	427	486	746	857	626	340	134	626	114
Long-term debt	1,495	1,496	1,496	1,496	2,244	1,995	1,995	1,981	1,981	1,481	1,481
Deferred taxes	546	542	537	491	526	530	277	197	144	144	144
Other LT liabilities	179	201	171	186	239	188	155	103	100	92	82
Non-controlling int	0	0	0	0	0	0	0	0	0	0	0
Shareholders' equity	3,631	3,862	4,333	4,576	4,637	4,452	4,113	3,750	3,836	3,858	3,814
Total liabilities and equity	6,264	6,727	6,964	7,235	8,391	8,021	7,165	6,372	6,195	6,201	5,634
Total debt	1,500	1,496	1,496	1,496	2,494	2,244	2,281	2,085	1,981	1,981	1,481
Net debt	722	419	260	10	397	1,995	2,151	1,929	1,637	1,422	1,281
Debt/capital	29%	28%	26%	25%	35%	34%	36%	36%	34%	34%	28%
Debt/equity	41%	39%	35%	33%	54%	50%	55%	56%	52%	51%	39%
Debt turns	**0.7**	**0.8**	**0.9**	**1.1**	**2.0**	**2.0**	**2.1**	**3.1**	**3.4**	**4.3**	**4.2**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
ENSCO International

Reuters	Bloomberg
ESV.N	ESV US

David Havens
Research Analyst
+1-212-250-3235
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Price at 5 Oct 2017 (USD)	5.83
Price target	6.00
52-week range	11.81 - 4.16

In Pursuit of Tier 1 Rigs

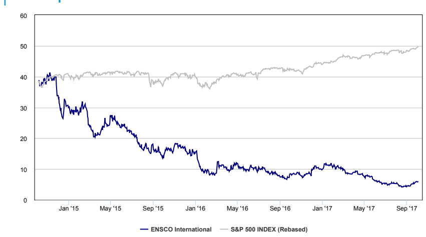
Initiating coverage with a Hold rating and a $6 price target

Consolidation will be a core focus for the offshore drillers as the severity of the downturn combined with what we expect will be a slow, laborious recovery encourages contractors to scale up their tier 1 rig exposure while retiring their lower quality rigs. That is what Ensco is attempting with its agreement to acquire Atwood Oceanics. While we understand the commercial rationale motivating the transaction, Ensco is buying optionality, not cash flow. The transaction consumes liquidity in a market that covets liquidity, and in return gets only about $250 million in backlog. We believe this adds uncertainty that the company can ill afford in this market. While this may be a prescient move by Ensco, we do not expect the market to give it credit until Ensco converts the optionality into cash flow.

Ensco buying tier 1 optionality with Atwood

This is the first of two major offshore transactions. Whereas Transocean is paying $3.4 billion for Songa Offshore which has $4.1 billion in backlog and provides Transocean $0.7 billion of annual revenues through 2022, Ensco is paying $1.8 billion for only about $250 million of backlog and about $120 million of revenue in 2018. Ensco is paying for optionality as it attempts to scale up its tier 1 asset exposure.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	28.3	6.2	-27.7
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,753.8
Shares outstanding (m)	300.8
Free float (%)	–
Volume (5 Oct 2017)	3,955,006
Option volume (und. shrs., 1M avg.)	272,758

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.75	-0.04A	-0.23
2Q EPS	0.51	-0.10A	-0.31
3Q EPS	0.21	-0.22	-0.63
4Q EPS	0.09	-0.22	-0.72
FY EPS (USD)	1.47	-0.57	-1.89
OLD FY EPS (USD)	1.51	–	–
% Change	-2.9%	–	–
P/E (x)	6.5	–	–
DPS (USD)	0.04	0.04	0.04
Dividend Yield (%)	0.4	0.7	0.7
Revenue (USDm)	2,571.4	1,816.1	1,603.7

Source: Deutsche Bank estimates, company data

Valuation

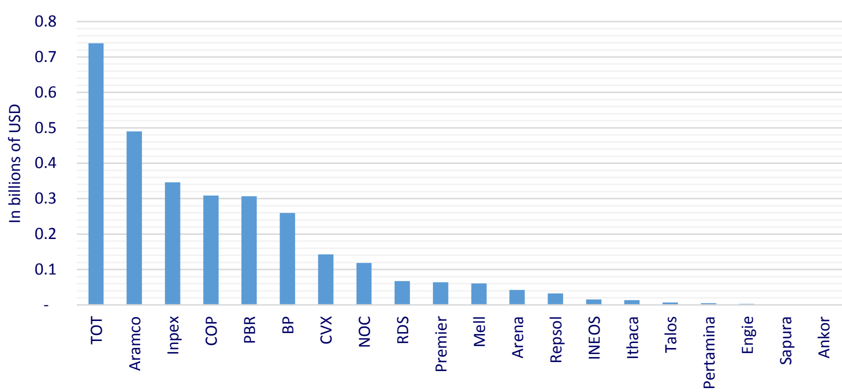
We are initiating coverage of Ensco with a $6 price target. This is 4.0x our estimate of the company's normalized EBITDA of $1.35 billion, which is almost two-turns below the 5.8x ten-year average multiple. The company is currently trading at 10x our fiscal 2018 EBITDA estimate of $0.48 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an inability to contract the rigs acquired in the Atwood transaction, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Key investment themes

Ensco has $3 billion of backlog split between floaters and jackups

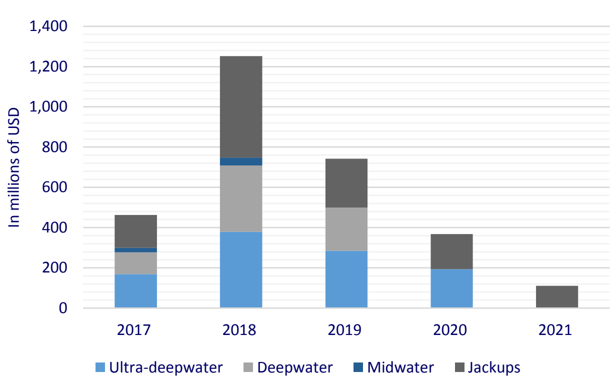
Ensco has the least customer concentration relative to its peers with its top five customers representing only 72% of total backlog versus most of its peers above 90%. Total SA is Ensco's largest customer with 24% of the total backlog and 72% of the ultra-deepwater backlog. The Atwood transaction adds only about $250 million of backlog, mainly from the Atwood Condor contract in Australia. Only about one-third of Ensco's capacity is booked for 2018, which drops to 20% in 2019. Only 20% of its ultra-deepwater capacity is booked in 2018, and that is before we pro-forma for Atwood's six ultra-deepwater rigs, only one of which has a contract extending through 2018.

Figure 308: Backlog by customer



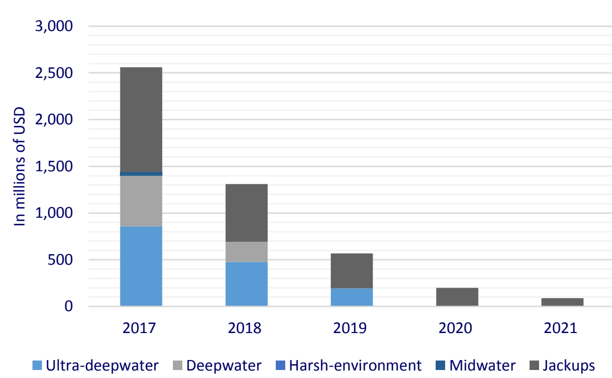
Source: Company reports, Deutsche Bank

Figure 309: Revenues in backlog



Source: Company reports, Deutsche Bank

Figure 310: Year-end backlog



Source: Company reports, Deutsche Bank

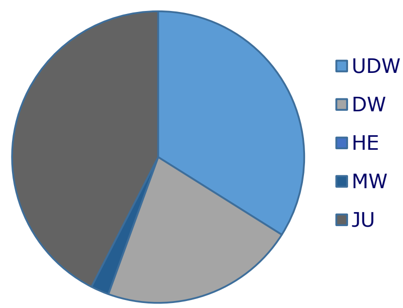
Figure 311: Ensco backlog details

Revenue in backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	169	379	285	193	0
Deepwater	109	330	215	0	0
Harsh-environment					
Midwater	22	39	0	0	0
Jackups	163	504	242	175	111
Total backlog	**463**	**1,252**	**742**	**368**	**111**

Total backlog	Abbrev	($bn)
Ultra-deepwater	UDW	1.0
Deepwater	DW	0.7
Harsh-environment	HE	
Midwater	MW	0.1
Jackups	JU	1.3
Total backlog		**3.0**

Days committed	2017	2018	2019	2020	2021
Ultra-deepwater	27%	20%	12%	6%	0%
Deepwater	100%	83%	56%	0%	0%
Harsh-environment					
Midwater	50%	25%	0%	0%	0%
Jackups	51%	40%	22%	16%	11%
Total backlog	**47%**	**36%**	**20%**	**11%**	**7%**

Backlog by rig type



Year-end backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	857	478	193	0	0
Deepwater	545	215	0	0	0
Harsh-environment					
Midwater	39	0	0	0	0
Jackups	1,121	616	374	200	89
Total backlog	**2,561**	**1,310**	**568**	**200**	**89**

	2017	**2018**	**2019**
Total debt	4,745	4,745	4,489
Debt / YE backlog	**1.9**	**3.6**	**7.9**

Backlog by customer ($m	#1	#2	#3	#4	#5
Ultra-deepwater	**TOT**	**CVX**	**BP**	**RDS**	**Talos**
Backlog	739	118	95	67	7
% of backlog	72%	12%	9%	7%	1%
Deepwater	**Inpex**	**PBR**			
Backlog	346	307			
% of backlog	53%	47%			
Harsh-environment					
Backlog					
% of backlog					
Midwater	**Mell**				
Backlog	61				
% of backlog	100%				
Jackups	**Aramco**	**COP**	**BP**	**NOC**	**Premier**
Backlog	490	309	164	118	64
% of backlog	38%	24%	13%	9%	5%

Top 5 customers in backlog		Percent	$bn
TOT	#1	24%	0.7
Aramco	#2	16%	0.5
Inpex	#3	11%	0.3
COP	#4	10%	0.3
PBR	#5	10%	0.3
Other		**28%**	**0.8**

Fleet composition	2017	2018	2019
Ultra-deepwater	14	15	15
Deepwater	3	3	3
Harsh-environment	-	-	-
Midwater	2	2	2
Jackups	32	33	33
Total in fleet	**51**	**53**	**53**

Source: Company reports, Deutsche Bank

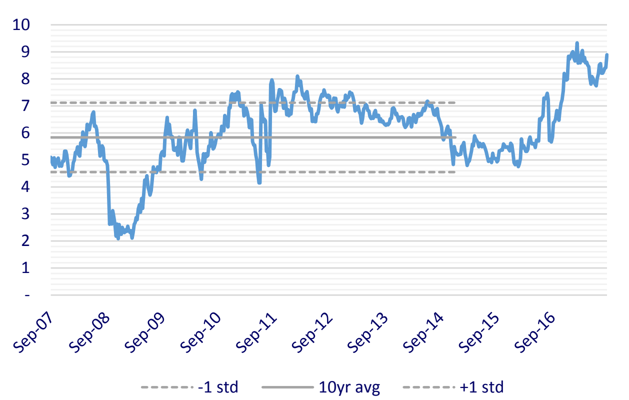
Valuation and risks

We are initiating coverage of Ensco with a $6 price target. This is 4.0x our estimate of the company's normalized EBITDA of $1.35 billion, which is almost two-turns below the 5.8x ten-year average multiple. The company is currently trading at 10x our fiscal 2018 EBITDA estimate of $0.48 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

In terms of steel value, we assess the trough net asset value at $6.70 per share, which assumes the market endures another three years of high volumes of cold-stacking once contracts expire and leading edge market rates that stay at breakeven levels ($160-170 kpd).

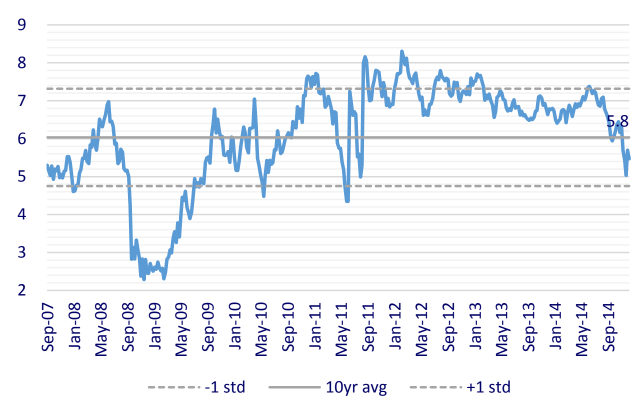
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an inability to contract the rigs acquired in the Atwood transaction, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Figure 312: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 313: The 5yr EV/EBITDA leading up to 2014

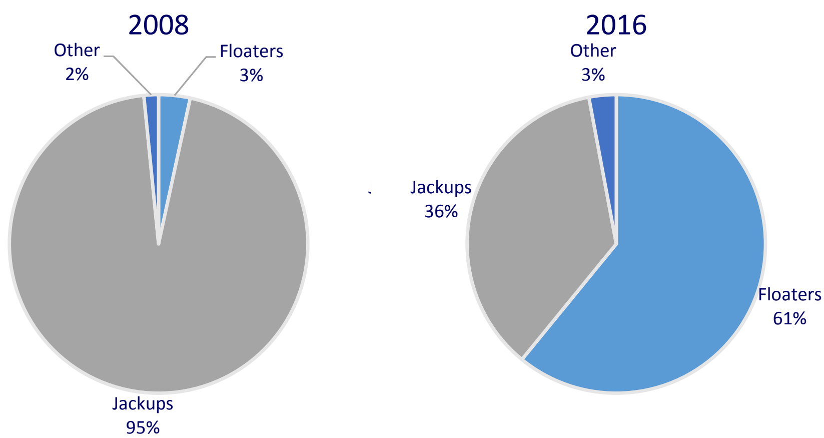


Source: Factset

Company description

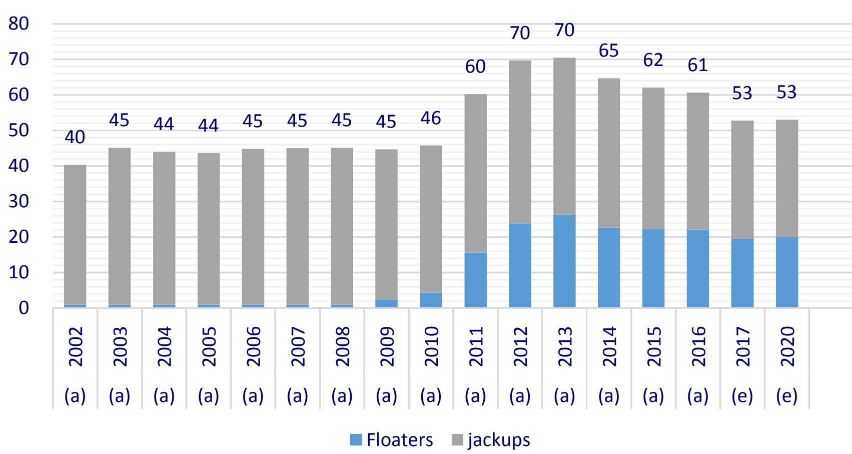
Ensco (ESV) is a contract drilling company with a fleet of 53 mobile offshore drilling rigs including 15 ultra-deepwater floaters, three deepwater and two midwater floaters, and 33 jackups. Over the last ten years, the company has repositioned itself as leading provider of ultra-deepwater rigs with the addition of 15 newbuilds consisting of eight high-specification drillships and seven 8500 series semis. The company also announced in May 2017 the agreement to acquire Atwood Oceanics (ATW), which has a fleet of six ultra-deepwater floaters and five high-specification jackups.

Figure 314: Revenues by rig type



Source: Company reports, Deutsche Bank

Figure 315: Change in fleet size and mix



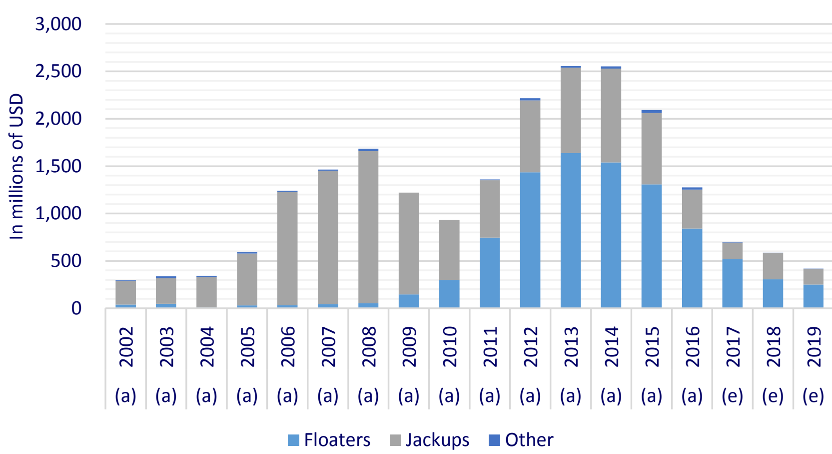
Source: Company reports

Principal Sources and Uses of Cash Flow

A more balanced mix of jackups and floaters than most of its peers

Ensco's principal source of cash flow has evolved from primarily jackups to now including the ultra-deepwater. The company's high water mark in terms of EBITDA was $2.4 billion in 2014, almost two-thirds of which came from its fleet of ultra-deepwater floaters. While we expect the deepwater markets to bottom in 2017, fiercely competitive pricing combined with some contract expiries is going to pressure EBITDA down to $0.5 billion in our view and even lower in 2019.

Figure 316: Segment EBITDA (excludes corporate G&A)



Source: Company reports, Deutsche Bank

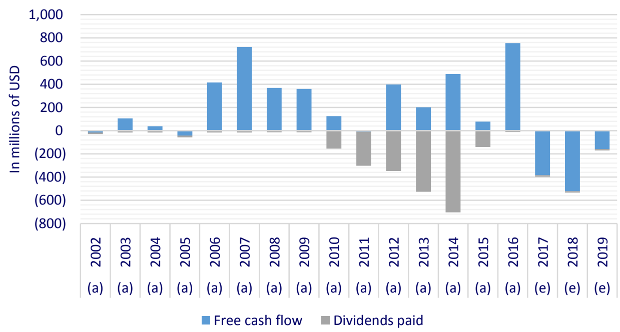
Ultra-deepwater cash flows declining further due to expiries and pricing

Ensco currently has eight of its 15 floaters idle with the potential for another three going idle in early 2018 upon completion of existing contracts. Four of the eight currently idled rigs are its 8500 series semis, which could all be idle by mid-2018. These rigs do not share the same degree of commercial marketability as Ensco's drillships in our view, and will linger in cold-stack longer than the higher-spec brethren. We do expect Ensco's fleet of eight drillships to be top of mind with customers, although pricing will likely be very competitive and ranging in the $160 – 180 range in 2018. If we assume all of its drillships return to work in this range and the DS-8 continues to amortize its contract with Total SA, and the seven semis remain idle in 2018, the segment EBITDA contribution would be about $270 million versus the $1.5 billion in 2014.

Jackup business turning up, but pricing also encountering some headwinds

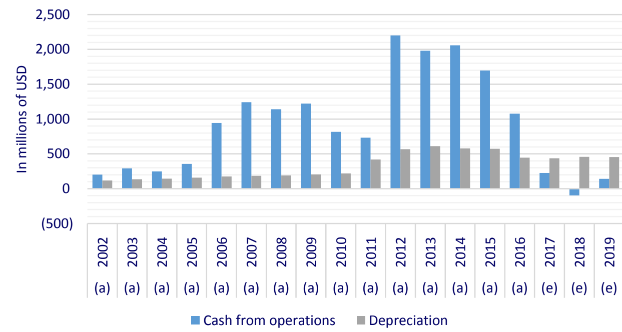
We would say half of Ensco's current jackup fleet are core marketable rigs. The other half are over 30 years old and are likely to be retired in the near future. We expect the jackup segment to bottom at about $175 million of EBITDA in 2017 and increase to $278 million in 2018. This compares to $1.0 billion of jackup EBITDA in 2014.

Figure 317: Free cash flow and dividends



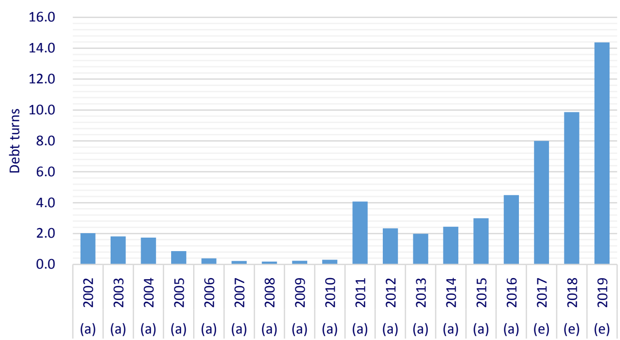
Source: Company reports, Deutsche Bank

Figure 318: Capex trend



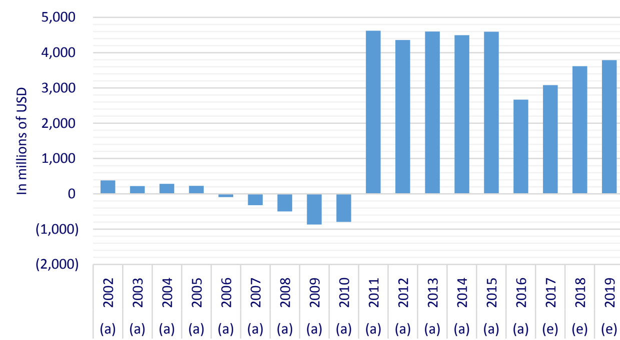
Source: Company reports, Deutsche Bank

Figure 319: Debt turns



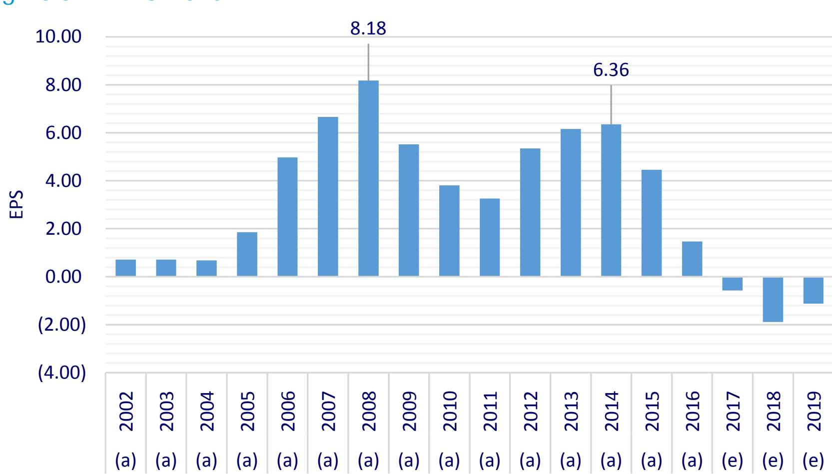
Source: Company reports, Deutsche Bank

Figure 320: Net debt



Source: Company reports, Deutsche Bank

Figure 321: EPS trend



Source: Company reports, Deutsche Bank

Figure 322: Fleet profile

Rig name	Water depth (ft)	Rig type	Year in service	Rig design	Backlog (yrs)	Backlog ($m)
Ultra-deepwater (15):						
ENSCO DS-10	10,000	DS-DP	2015	Samsung GF12000	1.1	67.3
ENSCO DS-9	10,000	DS-DP	2014	Samsung GF12000	-	-
ENSCO DS-8	10,000	DS-DP	2015	Samsung GF12000	3.1	719.8
ENSCO DS-7	10,000	DS-DP	2013	Samsung 12000	0.1	18.9
ENSCO DS-6	10,000	DS-DP	2012	Samsung	0.4	95.1
ENSCO DS-5	10,000	DS-DP	2011	Samsung	-	-
ENSCO DS-4	10,000	DS-DP	2010	Samsung	1.9	118.2
ENSCO DS-3	10,000	DS-DP	2010	Samsung Saipem 10000	-	-
ENSCO 8506	8,500	6th	2012	Ensco 8500	-	-
ENSCO 8505	8,500	6th	2012	Ensco 8500	-	-
ENSCO 8504	8,500	6th	2011	Ensco 8500	-	-
ENSCO 8503	8,500	6th	2010	Ensco 8500	0.1	7.0
ENSCO 8502	8,500	6th	2010	Ensco 8500	-	-
ENSCO 8501	8,500	6th	2009	Ensco 8500	-	-
ENSCO 8500	8,500	6th	2008	Ensco 8500	-	-
Deepwater (3):						
ENSCO 5006	6,200	4th	1999	Trosvik Bingo 8000	1.9	346.3
ENSCO 6002	5,700	4th	2001	DeHoop Megathyst Class	2.3	220.7
ENSCO 6001	5,600	4th	2001	DeHoop Megathyst Class	0.8	86.3
Midwater (2):						
ENSCO 5004	1,500	3rd	1982	Friede & Goldman 9500 Enhanced Pacesetter	0.8	60.7
ENSCO 5005	1,500	3rd	1982	Friede & Goldman L-1033 Enhanced Pacesetter	-	-
Jackups (33):						
ENSCO 100	350	IC	1987	LeTourneau 150-88-C Enhanced Gorilla Class	0.9	64.0
ENSCO 101	400	IC	2000	Keppel FELS KFELS MOD V A	-	-
ENSCO 102	400	IC	2002	Keppel FELS KFELS MOD V A	1.3	42.6
ENSCO 104	400	IC	2002	Keppel FELS KFELS MOD V B	-	-
ENSCO 105	375	IC	2002	Keppel FELS KFELS MOD V B	-	-
ENSCO 106	400	IC	2005	Keppel FELS KFELS MOD V B Bigfoot	5.3	165.3
ENSCO 107	400	IC	2006	Keppel FELS KFELS B Class Bigfoot	-	-
ENSCO 108	400	IC	2007	Keppel FELS KFELS B Class Bigfoot	-	-
ENSCO 109	350	IC	2008	Keppel FELS KFELS Super B Class	0.4	24.8
ENSCO 110	400	IC	2015	Keppel FELS KFELS MOD V B Bigfoot	3.0	118.5
ENSCO 120	400	IC	2013	Keppel FELS KFELS Super A Class	2.9	125.5
ENSCO 121	400	IC	2013	Keppel FELS KFELS Super A Class	0.4	15.4
ENSCO 122	400	IC	2014	Keppel FELS KFELS Super A Class	0.4	13.4
ENSCO 123	400	IC	2016	Keppel FELS KFELS Super A Class	-	-
ENSCO 140	340	IC	2016	LeTourneau Super 116E Class	-	-
ENSCO 141	340	IC	2016	LeTourneau Super 116E Class	-	-
ENSCO 54	300	IC	1982	Friede & Goldman L-780 MOD II	5.0	141.4
ENSCO 67	400	IC	1976	LeTourneau Class 84-C Modified	0.3	5.2
ENSCO 68	400	IC	1976	LeTourneau Class 84-C Modified	-	-
ENSCO 70	250	IC	1981	Hitachi Zosen K-1032N	-	-
ENSCO 71	225	IC	1982	Hitachi Zosen K-1032N	-	-
ENSCO 72	225	IC	1981	Hitachi Zosen K-1025N	0.1	2.8
ENSCO 75	390	IC	1999	LeTourneau Super 116 Class	0.0	0.5
ENSCO 76	350	IC	2000	LeTourneau Super 116 Class	1.3	75.1
ENSCO 80	225	IC	1978	LeTourneau Class 116-C Modified	1.3	32.8
ENSCO 81	350	IC	1979	LeTourneau Class 116-C	-	-
ENSCO 82	300	IC	1979	LeTourneau Class 116-C	-	-
ENSCO 84	250	IC	1981	LeTourneau Class 82 SD-C	3.9	101.7
ENSCO 87	350	IC	1982	LeTourneau Class 116-C	-	-
ENSCO 88	250	IC	1982	LeTourneau Class 82 SD-C	2.2	52.1
ENSCO 92	225	IC	1982	LeTourneau Class 116-C	5.3	183.3
ENSCO 96	250	IC	1982	Hitachi Zosen Drill Hope C-250	1.4	59.7
ENSCO 97	250	IC	1980	LeTourneau Class 82 SD-C	1	60

Source: Company reports, Deutsche Bank

Figure 323: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Floaters	254	475	1,539	2,708	3,137	2,869	2,337	1,566	1,080	711	709
Jackups	1,692	1,217	1,224	1,517	1,735	1,849	1,446	930	678	834	723
Other	0	0	52	83	75	92	152	76	58	58	58
Total revenue	1,946	1,693	2,815	4,308	4,947	4,811	3,934	2,571	1,816	1,604	1,491
Segment EBITDA:											
Floaters	146	299	747	1,434	1,638	1,540	1,308	841	519	304	250
Jackups	1,074	634	605	759	901	990	752	413	175	278	163
Other	0	0	8	25	17	24	33	21	5	5	5
Corporate	(64)	(86)	(121)	(145)	(147)	(132)	(118)	(101)	(106)	(106)	(106)
EBITDA	1,156	847	1,240	2,073	2,409	2,422	1,975	1,174	593	481	312
D&A	206	219	419	568	612	580	573	445	437	457	454
EBIT	951	628	821	1,505	1,797	1,842	1,402	728	156	24	(142)
Interest (expense)	0	0	(96)	(124)	(159)	(161)	(216)	(229)	(240)	(268)	(279)
Interest income	7	1	17	23	17	11	10	14	28	22	14
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	2	6	21	3	11	(4)	12	(6)	(1)	0	0
PBT	959	634	763	1,407	1,666	1,689	1,208	508	(56)	(222)	(407)
Income tax (expense)	(178)	(91)	(131)	(158)	(217)	(188)	(151)	(78)	(112)	(341)	73
Non-controlling interest	(5)	(6)	(5)	(7)	(10)	(14)	(9)	(7)	(5)	(5)	(5)
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	776	537	627	1,242	1,439	1,486	1,048	422	(172)	(568)	(339)
Discontinued ops	4	44	0	22	(5)	(1,952)	(17)	8	(0)	0	0
Unusual after-tax	0	(1)	(38)	100	(16)	(3,437)	(2,626)	460	(30)	0	0
Net income (GAAP)	779	580	589	1,365	1,418	(3,903)	(1,595)	890	(202)	(568)	(339)
Operating EPS	5.52	3.80	3.26	5.35	6.16	6.36	4.45	1.47	(0.57)	(1.89)	(1.13)
GAAP EPS	5.55	4.11	3.06	5.89	6.07	(16.90)	(6.93)	3.14	(0.67)	(1.89)	(1.13)
DPS	0.10	1.08	1.40	1.50	2.25	3.00	0.60	0.04	0.04	0.04	0.04
Diluted shares	140	141	192	230	231	232	232	279	301	301	301
EBITDA margin	59.4%	50.0%	44.0%	48.1%	48.7%	50.3%	50.2%	45.6%	32.7%	30.0%	20.9%
EBIT margin	48.8%	37.1%	29.2%	34.9%	36.3%	38.3%	35.6%	28.3%	8.6%	1.5%	-9.5%
Tax rate	19%	14%	17%	11%	13%	11%	13%	15%	-200%	-153%	18%
Utilization:											
Floaters	73%	80%	79%	86%	80%	77%	69%	54%	44%	30%	38%
Jackups	72%	76%	77%	85%	88%	88%	73%	60%	63%	76%	73%
Dayrates ($000):											
Floaters	425	369	343	360	408	451	416	360	342	321	255
Jackups	151	106	98	106	123	137	136	111	89	92	83

Source: Deutsche Bank

Figure 324: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	776	537	627	1,242	1,439	1,486	1,048	422	(172)	(568)	(339)
Depreciation	206	219	419	568	612	580	573	445	437	457	454
Deferred tax	20	14	(20)	18	6	(124)	(158)	29	26	0	0
Chg in receivables	158	110	(624)	27	(44)	(28)	301	221	15	52	5
Chg in payables	129	4	480	(286)	(17)	32	(149)	(79)	33	(16)	24
Other	(67)	(68)	(150)	631	(16)	111	83	39	(116)	(22)	(2)
Cash from operations	1,222	817	732	2,200	1,980	2,058	1,698	1,077	224	(97)	142
Capital expenditures	(861)	(691)	(742)	(1,802)	(1,779)	(1,569)	(1,620)	(322)	(608)	(425)	(300)
Free cash flow	360	126	(9)	398	201	489	78	755	(383)	(522)	(158)
	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	(184)	(2,656)	0	0	0	0	0	0	0	0
Asset sales	3	160	47	62	33	169	2	10	0	0	0
Dividends paid	(14)	(154)	(292)	(348)	(526)	(703)	(141)	(12)	(12)	(12)	(12)
ESPP | options	10	1	40	0	0	3	0	0	0	0	0
Equity issuance, net	(7)	(6)	0	67	22	0	0	586	0	0	0
Debt issuance, net	(17)	(17)	2,375	(173)	(48)	1,186	6	(14)	(537)	0	(256)
Other	17	(16)	(123)	50	(5)	112	(66)	(24)	(7)	0	0
Chg in cash	352	(91)	(620)	56	(322)	1,257	(121)	1,301	(940)	(534)	(426)
FCF per share	2.57	0.89	(0.05)	1.73	0.87	2.11	0.34	2.71	(1.27)	(1.73)	(0.52)
Capex / revenue	0.44	0.41	0.26	0.42	0.36	0.33	0.41	0.13	0.33	0.27	0.20
Capex / depreciation	4.18	3.15	1.77	3.17	2.91	2.71	2.83	0.72	1.39	0.93	0.66

Source: Deutsche Bank

Figure 325: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	1,141	1,051	431	487	166	1,422	1,301	2,602	1,663	1,129	703
Accounts receivable	325	215	838	811	856	883	582	361	346	294	289
Other current assets	187	171	376	425	514	629	402	316	301	256	251
Total current assets	1,653	1,437	1,645	1,724	1,535	2,935	2,285	3,279	2,309	1,678	1,243
Net PP&E	4,477	5,050	12,424	13,146	14,311	12,535	11,088	10,919	11,114	11,082	10,928
Goodwill	336	336	3,289	3,274	3,274	276	0	0	0	0	0
Other assets	281	229	514	422	353	314	264	176	127	108	106
Total assets	6,747	7,052	17,871	18,565	19,473	16,060	13,637	14,375	13,550	12,868	12,276
Accounts payable	159	164	644	358	341	373	225	146	179	163	187
Accrued expenses	309	168	507	584	659	697	551	377	300	255	251
Current debt	17	17	173	48	48	35	0	332	0	256	559
Other current liabilities	0	0	0	0	0	0	0	0	0	0	0
Total current liabilities	485	349	1,323	990	1,047	1,105	776	854	479	674	997
Long-term debt	257	240	4,878	4,798	4,719	5,886	5,895	4,943	4,745	4,489	3,930
Deferred taxes	377	358	340	352	362	180	4	0	0	0	0
Other LT liabilities	121	139	446	573	546	667	445	323	273	232	228
Non-controlling int	8	6	5	6	7	7	4	4	8	13	18
Shareholders' equity	5,499	5,960	10,879	11,846	12,792	8,216	6,513	8,251	8,045	7,460	7,105
Total liabilities and equity	6,747	7,052	17,871	18,565	19,473	16,060	13,637	14,375	13,550	12,868	12,276
Total debt	274	257	5,050	4,846	4,766	5,920	5,895	5,275	4,745	4,745	4,489
Net debt	(867)	(793)	4,619	4,359	4,601	4,498	4,594	2,672	3,082	3,616	3,786
Debt/capital	5%	4%	32%	29%	27%	42%	48%	39%	37%	39%	39%
Debt/equity	5%	4%	46%	41%	37%	72%	91%	64%	59%	64%	63%
Debt turns	**0.2**	**0.3**	**4.1**	**2.3**	**2.0**	**2.4**	**3.0**	**4.5**	**8.0**	**9.9**	**14.4**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Forum Energy Tech

Reuters	Bloomberg
FET.N	FET US

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Research Analyst
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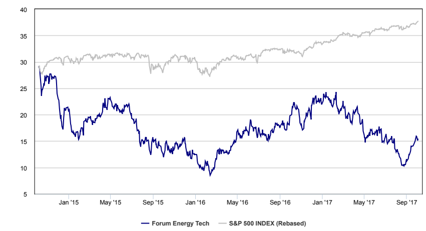
Price at 5 Oct 2017 (USD)	15.50
Price target	17.00
52-week range	24.30 - 10.35

Price/price relative



Performance (%)	1m	3m	12m
Absolute	36.9	-5.8	-23.2
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,489.9
Shares outstanding (m)	96.1
Free float (%)	89
Volume (5 Oct 2017)	157,703
Option volume (und. shrs., 1M avg.)	132

Source: Deutsche Bank

Forum Energy Technologies (FET)

Initiating coverage with a Hold rating and $17 price target

FET has a solid positive free cash flow track record, but the source of cash is changing significantly as Drilling & Subsea contributions go from the majority to the minority, and Completions segment benefits from the onshore recovery and the retooling of the US frac fleet. Pricing has come back in the frac business with customer orders rising into year-end. Production & Infrastructure is also seeing orders moving higher this year. We expect 2H17 to benefit from the recent consolidation of its Global Tubing business where FET acquires the remaining 52% interest with a $60m EBITDA run rate expected during 2018.

Industry favoring frac exposure

The frac market is one of the very few seeing scarcity value. Pricing is coming back, with FET seeing a backlog build in its Stimulation & Intervention business on strong demand, while historically the segment has been demand-and-ship. Pricing discussions with customers have begun, with FET responding by adding significantly to headcount. We expect to see a benefit in 2H17 with pricing beginning to materialize, albeit at a slower pace than prior cycles.

1H17 revenues weighted 88% onshore vs 12% offshore

Forum has expanded its onshore business to capture market share in US upstream, while Valves (Production & Infrastructure) segment had record 2Q17 orders, even excluding the impact of the Jan 2017 Cooper acquisition. An offshore recovery continues to lag the uptick in US land currently benefitting FET's revenue mix. 2Q17 Orders in Completions were up 31% and in Stimulation & Intervention up over 45% with increased customer spending across nearly all products. We expect 2H17 incremental margins stronger vs 1H17 due to pricing materializing and absorption of ramp up costs. Management guided to 3Q17 EPS loss of $0.07-$0.04.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.22	-0.14A	0.02
2Q EPS	-0.19	-0.10A	0.04
3Q EPS	-0.19	-0.04	0.07
4Q EPS	-0.16	0.00	0.09
FY EPS (USD)	-0.76	-0.27	0.23
OLD FY EPS (USD)	-0.76	–	–
% Change	0.6%	–	–
P/E (x)	–	–	67.3
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	587.6	831.4	1,007.7

Source: Deutsche Bank estimates, company data

Valuation & Risks

Our $17 price target is 6.8x our estimate of the company's normalized EBITDA power of $250 million, which is a 1.0 turn discount to its 7.8x average multiple leading up to the 2014 collapse in oil prices. The company has $400 million of total debt and generated solid free cash flow through 2016 with normalized EBITDA above our current range.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a decrease in new frac capacity in the US, and 4) and a subsequent move lower in pricing and margins.

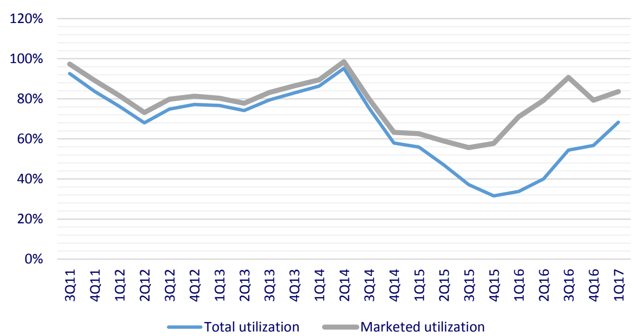
Key investment themes

Consumables seeing sharp demand increase

Pressure pumping supply/demand trends are continuing, driven by a rising well count, increased pad drilling, more wells per pad and an increasing inventory of DUCs (drilled but uncompleted wells). Frac fleets are also incorporating more hhp, averaging about 50k now. The increase is to accommodate the larger pads, which are keeping crews on location longer, thus in order to accommodate maintenance rotations and suitable uptime, contractors have increased fleet sizes.

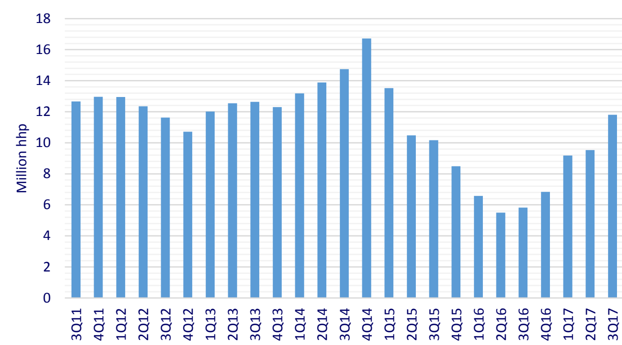
As pumpers reactivate fleets, FET has seen a sharp increase in consumables and fluid ends. Frac demand industry-wide has recovered to about 12 million HHP versus 17 million at the peak, and less than 6 million at the trough. FET's business is driven 40% by well count and well construction, 25% valves, 25% rig count and 10% subsea activity. New products like the frac manifold trailer and 7,500 PSI mud pump fluid ends will see demand as they push E&Ps up the technology curve, reduce setup/maintenance cost and reduce component change-out time up to 75%. The new mud pump also increases flow rates, complementing longer laterals and increases in the horizontal rig count. To meet demand, FET expects capex of $30 million in 2017.

Figure 326: Total vs. marketed frac hhp utilization



Source: IHS Markit, Deutsche Bank

Figure 327: US frac hhp demand



Source: IHS Markit, Deutsche Bank

Consumables benefit in a flat to down rig count scenario

The Consumables line will benefit from a stable or down rig count as customers will use opex to maintain heavily-utilized equipment. At current pace, less mud pumps will need upgrade in 2H17 vs 1H. Completions related products will continue to see good activity across centrifugal pumps, Little Tripper catwalks and bearings. Drilling product line revenues are tracking for a small sequential decline in 3Q17, and we may see additional uplift in 4Q as some customers may upgrade lower spec rigs to high spec. Benefit to FET totals $0.5-$2.0 million/rig and includes upgrading catwalks, extending reach and height, and 7,500 psi upgrades. In some cases, we could see handling tools and condition based monitoring.

Stimulation & Intervention lead times extending on strong backlog

Customers have begun pricing discussions for Stimulation & Intervention (S&I) with lead times extending. The segment has added a significant number of people in 2017 with the benefit to begin in 2H17 as pricing materializes in 4Q17. The S&I business has historically been build-and-ship but sharp increases in demand have built a backlog. In Production Equipment, lead times continue to extend with a strong backlog into 4Q17. The 4Q orders were booked in 1Q17 so we expect pricing uplift will begin to appear late-4Q17 and into 2018. For capital equipment orders the Middle East has remained strong, with one customer indicating tenders could happen in 4Q17, though we expect a price below $50 oil could push the tender to 2018.

3Q17 guidance for growth across the onshore-focused segments

Across the segments, management guided 3Q17 Completions growth strong, Subsea flat, D&S decline, and Production/Infrastructure to see significant growth. Of the strong 2Q17 completions growth, power ends were 55% newbuilds and 45% refurbishments or replacements. We expect going forward refurbishments to become a bigger percentage with capital equipment shrinking slightly.

Orders uptick continues, positive US and Intl market share view

2Q17 completions orders increased 31% sequentially and over 45% for Stimulation & Intervention with customer spending increasing across nearly all product offerings. Year-to-date FET has received orders for 480,000 horsepower of power ends. In 2Q it received orders for 8 manifold trailers (ICBM), and several orders for the Race Track suction manifold. With price improvement in pressure pumping orders showing up, we expect to see benefit in 2H17 results. Valves (Production & Infrastructure segment) saw record orders in 2Q17 – even excluding impact of Cooper acquisition – and without the uplift from the new manufacturing facility in Saudi Arabia. The facility is on-track to be operational in 2018. Management sees US upstream demand up while US midstream flat-to-up and gaining market share. Internationally both midstream and downstream are active, and FET is attempting to gain market share. The company is increasing its presence in Southeast Asia to penetrate the midstream and downstream markets. Offshore continues to lag with Drilling & Subsea orders down 21% in 2017. Subsea orders are now expected to remain at low levels for an extended period, weighted toward non-oil/gas activity.

Valuation and risks

Our $17 price target is 6.8x our estimate of the company's normalized EBITDA power of $250 million, which is a 1.0 turn discount to its 7.8x average multiple leading up to the 2014 collapse in oil prices. The company has $400 million of total debt and generated solid free cash flow through 2016 with normalized EBITDA above our current range.

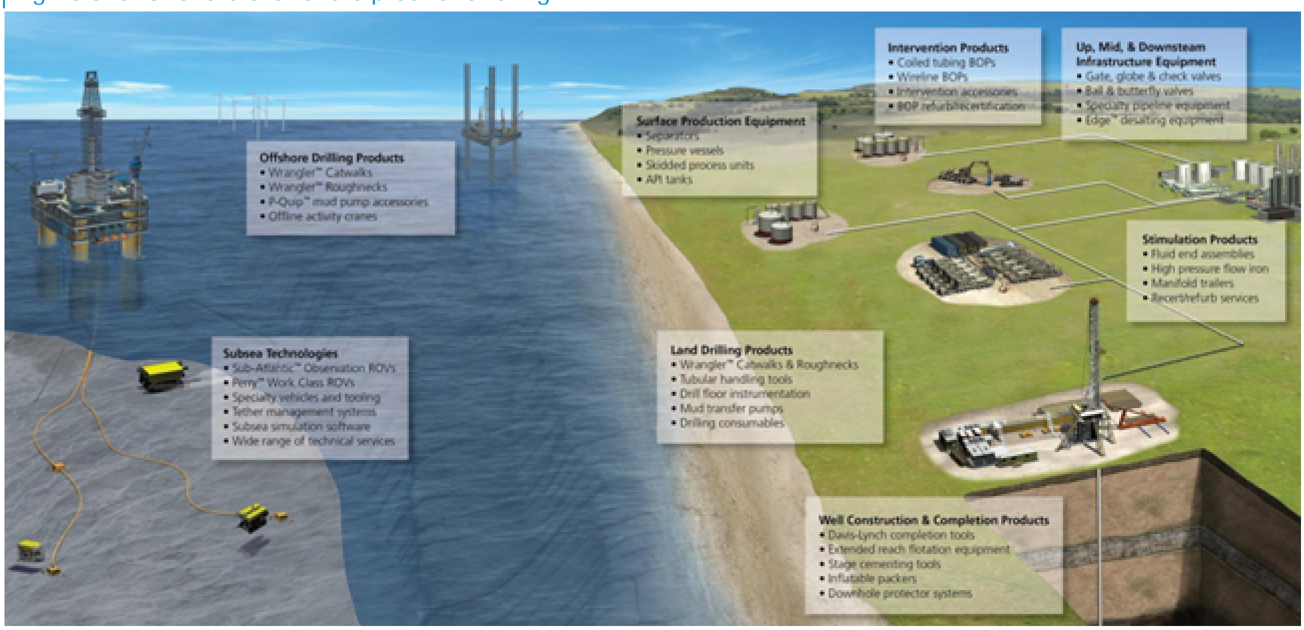
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a decrease in new frac capacity in the US, and 4) and a subsequent move lower in pricing and margins.

Company description

Forum Energy Technologies (FET) was founded in 2010 following the merger of Forum Oilfield Technologies, Triton Group, Subsea Services International, Global Flow Technologies and Allied Technology. It's major legacy brands include Perry and Sub-Atlantic™ (ROVs); B+V Oil Tools, P-Quip, Pipe Wranglers and Vanoil (tubular handling); Dynacon (LARS and winches); and Davis-Lynch, Cannon and Merrimac (downhole products).

The company operates today in three reporting segments: Drilling & Subsea (39% of 2016 revenues), Production & Infrastructure (40%), and Completions (21%). Over half (62%) of its revenues are derived in the US, 13% Europe and Africa, 9% Asia Pacific, 7% Canada, 5% Latin America and 4% Middle East. The company is growing its midstream and downstream operations internationally, specifically Southeast Asia. The Middle East remains a strong pipeline of capital equipment orders. In 1H17 88% of revenues came from its onshore business and 12% from offshore.

Figure 328: Onshore & offshore product offering



Source: Company reports, Deutsche Bank

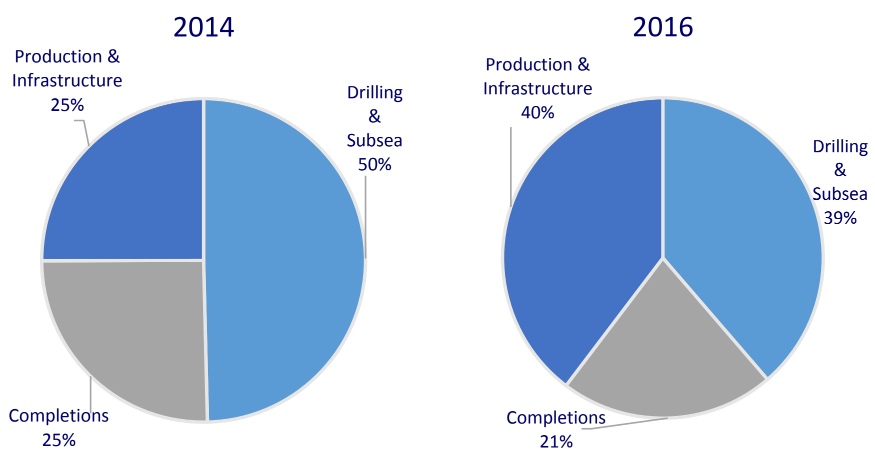
Figure 329: Reporting segments

Forum Energy

Drilling & Subsea	Completions
- Capital equipment	- Casing and cementing equipment
- Expendable drilling products	- Cable protectors for completions
- Subsea ROVs, trenchers, specialty parts	- Wireline flow controls
- Subsea technical services & rental items	- Composite plugs
Production & Infrastructure	- Frac pumps
- Engineered systems & production equipment	- Pump consumables & flow iron
- Field services	- Coiled tubing
- Oil & produced water treating equipment	- Wireline cable
- Industrial valves	- Pressure control equipment

Source: Company reports, Deutsche Bank

Figure 330: Segment revenue mix



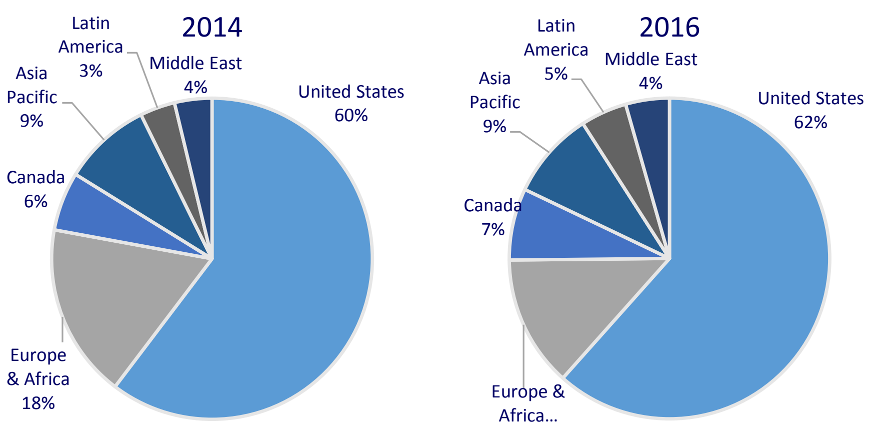
Source: Company reports

Principal Sources and Uses of Cash Flow

Increasingly focused on production phase of offshore life cycle

FET remains committed to the US onshore business, a significant driver its positive free cash flow record. The company expanded its Completions business from 0% of 2013 revenues to 27% at 2Q17, as the Drilling & Subsea segment became a smaller piece of the pie (32% of 2Q17 revenues vs 45% in 2015). As a result EBIT margins have been more resilient, and are poised to bounce back faster than some peers. Book-to-bill ratios have increased in 2017 across Completions and Production & Infrastructure, while Drilling & Subsea ticked down slightly from 0.95 in 2016 to 0.84 at 2Q17. The company is attempting to diversify its geographic and revenue mix toward more international and midstream/downstream work. We like the strategy but wait for the execution.

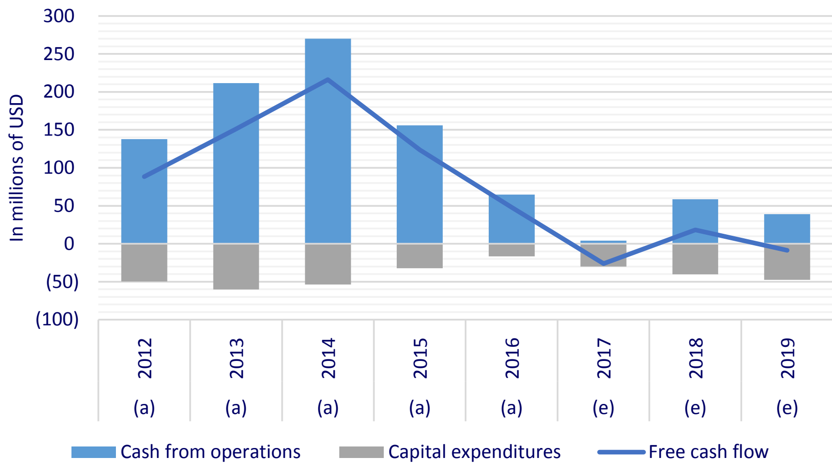
Figure 331: Revenue mix



Source: Company reports, Deutsche Bank

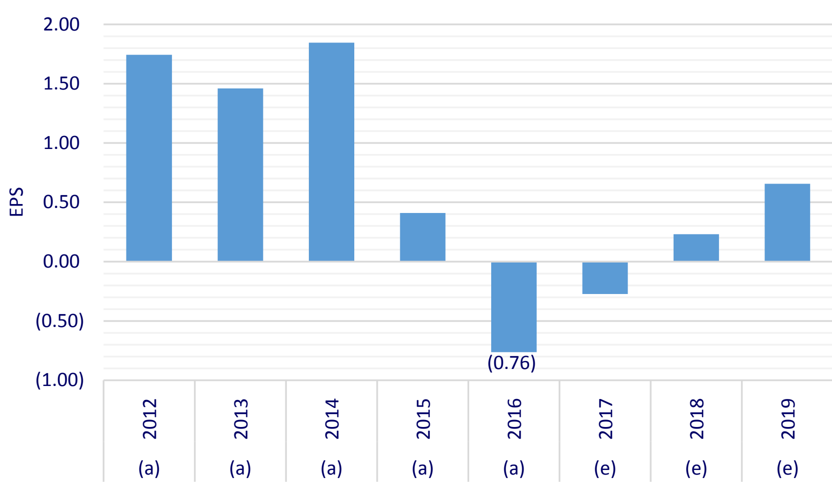
The Middle East and Asia Pacific regions have been bright spots during the downturn and we are hearing of upcoming rig tenders in the Middle East, which would benefit FET should it win the work. At 2Q17 the revenue mix was 62% US vs 38% Int'l, although we would caution at entering a price knife-fight solely to win market share. FET has assembled a strong group of businesses since its IPO in 2012 but its smaller size could mean margin pressure internationally should it too aggressively pursue market share. It has a strong balance sheet – historically 1.7x debt turns – has seen leverage increase with $400 million of total debt ($117mln net) today. While $30 million is budgeted for capex this year and 2018 customer visibility still hazy, we are looking for a sustainable path back to positive free cash flow and a larger, more stable internationally business mix benefit.

Figure 332: Positive free cash flow track record



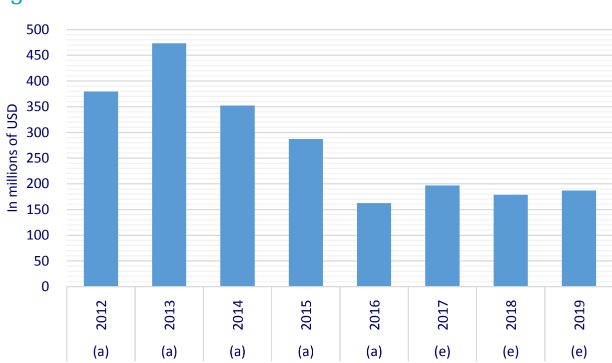
Source: Company reports, Deutsche Bank

Figure 333: Earnings per share



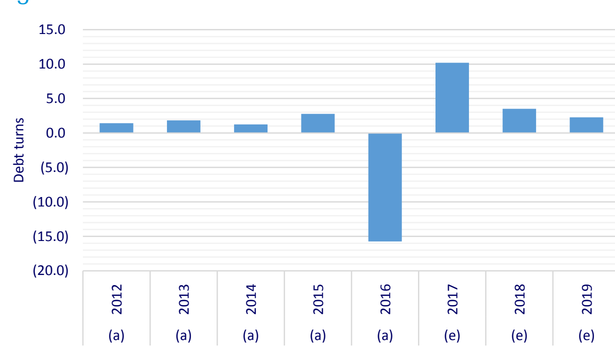
Source: Company reports, Deutsche Bank

Figure 334: Net debt



Source: Deutsche Bank

Figure 335: Debt turns



Source: Deutsche Bank

Figure 336: Income Statement

	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:								
Drilling & Subsea	827	941	864	487	228	258	273	314
Completions	0	0	441	267	127	227	294	350
Production & Infrastructure	589	585	436	320	234	349	443	523
Eliminations	(1)	(1)	(2)	(1)	(1)	(2)	(2)	(2)
Total revenues	1,415	1,525	1,740	1,074	588	831	1,008	1,185
Segment EBITDA:								
Drilling & Subsea	199	207	168	73	(11)	(69)	21	33
Completions	0	0	147	61	1	31	69	91
Production & Infrastructure	110	101	64	35	11	29	59	90
Other	(16)	(29)	(39)	(27)	(26)	48	(34)	(39)
Total EBITDA	293	280	340	142	(25)	39	114	176
Segment D&A:								
Drilling & Subsea	38	44	35	34	30	(46)	22	24
Completions	0	0	20	25	25	18	20	17
Production & Infrastructure	13	13	8	7	7	10	12	15
Corporate and other	1	3	1	(0)	0	77	(2)	(7)
Total D&A	52	61	65	66	62	59	52	49
Segment EBIT:								
Drilling & Subsea	161	163	133	39	(41)	(23)	(1)	10
Completions	0	0	127	36	(24)	14	49	73
Production & Infrastructure	97	87	56	28	5	19	47	75
Corporate and other	(18)	(31)	(41)	(26)	(27)	(30)	(32)	(32)
EBIT	241	219	275	77	(87)	(20)	62	127
Interest (expense)	(16)	(18)	(30)	(30)	(27)	(26)	(27)	(27)
Interest income	0	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	3	0	0
Other income	(2)	(3)	(0)	0	0	(2)	0	0
PBT	223	198	245	47	(114)	(46)	35	100
Income tax (expense)	(71)	(60)	(69)	(10)	45	20	(13)	(37)
Non-controlling interest	(0)	(0)	(0)	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0
Net income (operating)	152	138	176	38	(70)	(26)	22	63
Discontinued ops	0	0	0	0	0	(4)	0	0
Unusual after-tax	0	(9)	(2)	(157)	(13)	(67)	0	0
Net income (GAAP)	**152**	**129**	**174**	**(119)**	**(82)**	**(97)**	**22**	**63**
Operating EPS	**1.74**	**1.46**	**1.85**	**0.41**	**(0.76)**	**(0.27)**	**0.23**	**0.66**
GAAP EPS	1.74	1.37	1.83	(1.31)	(0.90)	(1.01)	0.23	0.66
DPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diluted shares	87	95	95	91	91	96	96	96
EBITDA margin	20.7%	18.3%	19.5%	13.3%	-4.3%	4.7%	11.3%	14.8%
EBIT margin	17.0%	14.4%	15.8%	7.1%	-14.8%	-2.4%	6.1%	10.7%
Tax rate	32.0%	30.1%	28.0%	20.4%	39.1%	43.2%	37.0%	37.0%
EBITDA margins								
Drilling & Subsea	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Completions	24.0%	22.0%	19.5%	15.0%	(4.7%)	(26.6%)	7.5%	10.6%
Production & Infrastructure	0.0%	0.0%	33.2%	22.8%	0.5%	13.7%	23.4%	25.9%

Source: Deutsche Bank

Figure 337: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	152	138	176	38	(70)	(26)	22	63
Depreciation	52	61	65	66	62	59	52	49
Deferred tax	(6)	16	(3)	(23)	(24)	(24)	0	0
Chg in receivables	13	1	(45)	146	29	(61)	(18)	(40)
Chg in inventories	(100)	33	(26)	0	57	(44)	(15)	(84)
Chg in payables	(5)	(1)	63	(111)	4	49	9	34
Other	33	(36)	40	41	6	52	8	17
Cash from operations	138	211	270	156	65	4	58	39
Capital expenditures	(50)	(60)	(54)	(32)	(17)	(30)	(40)	(47)
Free cash flow	88	151	216	124	48	(26)	18	(9)
Acquisitions	(140)	(182)	(38)	(61)	(4)	(9)	0	0
Asset sales	5	1	12	2	10	2	0	0
Dividends paid	0	0	0	0	0	0	0	0
ESPP | options	0	0	0	0	0	0	0	0
Equity issuance, net	321	1	(86)	(1)	87	(3)	0	0
Debt issuance, net	(251)	92	(84)	(26)	(0)	(1)	(0)	(0)
Other	13	(65)	17	(5)	(15)	5	0	0
Chg in cash	36	(1)	37	33	125	(32)	18	(9)

Source: Deutsche Bank

Figure 338: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	41	40	77	109	234	202	220	212
Accounts receivable	229	250	287	139	105	169	187	228
Inventories	455	441	462	424	339	392	406	491
Other current assets	50	79	70	46	71	43	48	58
Total current assets	775	809	895	718	750	806	861	988
Net PP&E	153	180	190	187	152	138	126	125
Goodwill	696	802	798	669	653	596	596	596
Other assets	269	377	338	313	281	284	285	286
Total assets	1,893	2,169	2,222	1,886	1,835	1,824	1,868	1,994
Accounts payable	99	100	128	77	74	127	137	171
Current debt	21	1	1	0	0	1	1	1
Other current liabilities	161	119	154	74	68	78	87	105
Total current liabilities	281	220	282	152	142	207	225	278
Long-term debt	400	512	428	396	397	398	398	397
Other LT liabilities	50	106	116	81	61	46	51	61
Shareholders' equity	1,161	1,330	1,395	1,257	1,235	1,173	1,195	1,258
Total liabilities and equity	1,893	2,169	2,222	1,886	1,835	1,824	1,868	1,994
Total debt	421	513	429	396	397	399	399	399
Net debt	380	473	352	287	162	197	179	187
Debt/capital	27%	28%	24%	24%	24%	25%	25%	24%
Debt/equity	36%	39%	31%	32%	32%	34%	33%	32%
Debt turns	**1.4**	**1.8**	**1.3**	**2.8**	**(15.7)**	**10.2**	**3.5**	**2.3**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

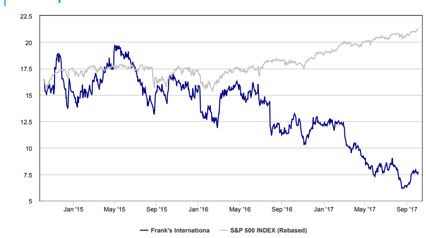
Company
Frank's International

Reuters	Bloomberg
FI.N	FI US

David Havens
Research Analyst
+1-212-250-3235
david.havens@db.com

Price at 5 Oct 2017 (USD)	7.67
Price target	7.00
52-week range	13.23 - 6.19

Price/price relative



Performance (%)	1m	3m	12m
Absolute	20.3	-10.0	-39.0
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,709.1
Shares outstanding (m)	222.8
Free float (%)	30
Volume (5 Oct 2017)	247,015
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Market Share Strategy in a Tough Offshore Environment

Initiating with a Hold rating and an $7 price target

Frank's is the principal player in the deepwater tubular running services (TRS) business, which is encountering a number of significant challenges as the deepwater market endures the most severe downturn in history. The company has been successful in gaining international market share in effort to restore its earnings power, but the base price for FI's primary services remains under pressure. We believe the deepwater is bottoming and is showing signs of a recovery, but the recovery is likely to be very laborious. While management has managed the downturn with peer leading fiscal responsibility, the macro outlook is too challenging at this point to endorse a rapid revision upward in earnings.

US onshore markets are improving, but TRS is highly fragmented

The US onshore environment is challenging its onshore business model. The company is exploring different business models as it looks to shift mix to a rental business and away from full service TRS. Land drillers in particular are interfering in the market as they look to boost their own daily margins with increasingly more service content, with TRS a primary target.

Gaining international market share, targeting Middle East, Norway and Brazil

The company is looking to take advantage of its no debt balance sheet and score some market share from those of its competitors that are otherwise distracted with restructuring efforts. The company has had some successes with international markets to the focus as FI will be at about 70% market share in the Gulf of Mexico deepwater by 1Q18.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.00	-0.12A	-0.08
2Q EPS	-0.13	-0.12A	-0.07
3Q EPS	-0.13	-0.11	-0.06
4Q EPS	-0.18	-0.10	-0.05
FY EPS (USD)	-0.47	-0.45	-0.26
OLD FY EPS (USD)	–	–	–
% Change	–	–	–
P/E (x)	–	–	–
DPS (USD)	0.45	0.30	0.30
Dividend Yield (%)	3.4	3.9	3.9
Revenue (USDm)	487.5	476.5	534.9

Source: Deutsche Bank estimates, company data

Valuation and risks

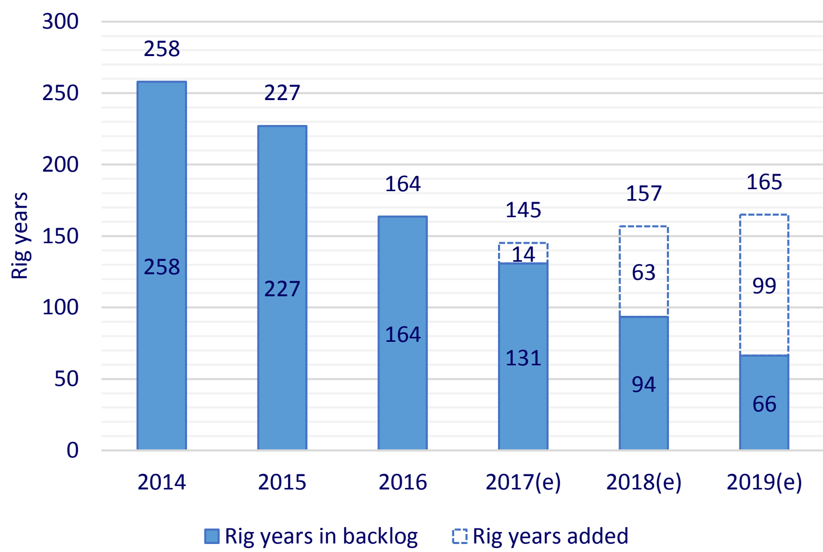
Our $7 price target is 6.9x our estimate of the company's normalized EBITDA power of $190 million. This is in-line with the average 6.9x multiple leading up to the 2014 collapse in oil prices. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) an inability to gain market share to restore earnings. Upside risk includes a more rapid offshore recovery stemming from a rise in commodity prices.

Key investment themes

The base price for FI's services remains under pressure

Approximately 75% of FI's business comes from the offshore, largely the deepwater. The timing of a sustained offshore recovery remains uncertain, but activity is bottoming in the deepwater, albeit with limited upside in the next few years. Lower activity in the Gulf of Mexico has battered its US Services margins as decremental margins can be 100% as rigs come off contract. Activity in the GoM should level out, but only after 3Q17 offshore US revenues take another 15% leg down according to management. On the bright side, the company was recently awarded a six rig long-term commitment in the GoM that begins in 4Q17 and should be ramped up in 1Q18. This will elevate FI's GoM market share to about 70%.

Figure 339: Deepwater drilling outlook (DBe)



Source: ODS-Petrodata, Deutsche Bank

The US onshore business is improving, but TRS revenues are lagging the rig count has FI concedes some low price market share in an effort to preserve onshore margins. We expect the US land drillers to keep interfering in the US TRS market as they seek out service content to boost daily margins.

Valuation and risks

Our $7 price target is 6.9x our estimate of the company's normalized EBITDA power of $190 million. This is in-line with the 6.9x average multiple leading up to the 2014 collapse in oil prices. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) an inability to gain market share to restore earnings. Upside risk includes a more rapid offshore recovery stemming from a rise in commodity prices.

Company description

Frank's International (FI) is global leader in tubular running services (TRS) for onshore, offshore, and the more complex deepwater and ultra-deepwater high pressure/high temperature (HP/HT) applications. FI also manufactures and sells large outer diameter (OD) pipe, connectors and casing attachments, and maintains an inventory of large OD pipe from third-party mills. FI has one of the industry's largest inventories of tubulars and connectors. The company also provides fabrication and welding services for offshore projects, but more specifically for drilling and production risers, flowlines and pipeline end terminations, as well as long length tubulars for use as caissons or pilings.

In November 2016, the company acquired Blackhawk Specialty Tools to diversify into well construction and intervention. Blackhawk has a particular expertise in cementing tools.

Figure 340: Reporting segments

Frank's International

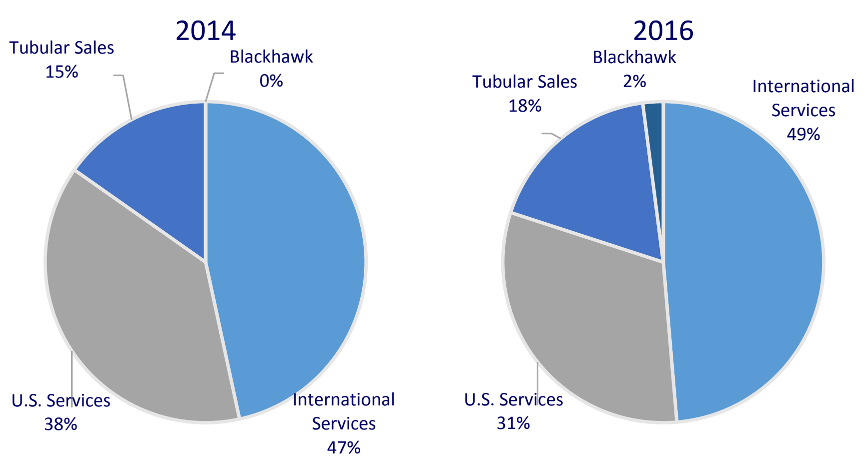
International Services / US Services
- Tubular running services (TRS)
  - Top drive casing running tools (CRT)
  - Casing-while-drilling (CwD)
  - Automated TRS solutions
  - Corrosion resistant alloy (CRA) TRS

Tubular Sales
- Manufacturing and distribution of:
  - Large outer diameter (OD) pipe
  - Connectors
  - Casing attachments

Blackhawk
- Cementing tools

Source: Company reports

Figure 341: Revenue mix by reporting segment



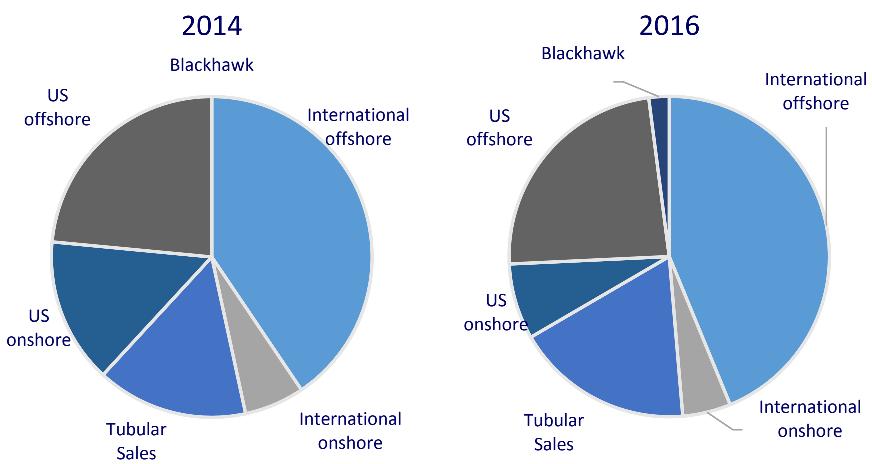
Source: Deutsche Bank

Principal Sources and Uses of Cash Flow

Tubular running services is core business, offshore is FI's principal market

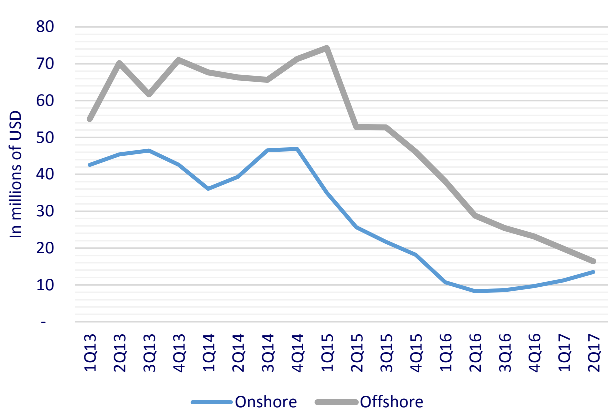
Frank's core business is tubular running services (TRS) and its principal markets are the Gulf of Mexico, West Africa, and the US onshore. Approximately 75% of its overall revenues are generated from offshore applications, primarily in the deepwater. The significant majority of revenues from its International Service segment is from deepwater as it is in the US Services segment. The deepwater markets are highly specialized and complex, thus there is a limited competitive landscape. Its most direct competitor is Weatherford, which has a better shallow water market share versus FI, and FI has a better position in the deepwater. Following the award on six new rigs in the US Gulf of Mexico, FI will have about 70% market share in the US GoM. The company is currently targeting higher penetration in the Middle East, Norway (where Odfjell has a leading market share), and Brazil.

Figure 342: Revenue mix



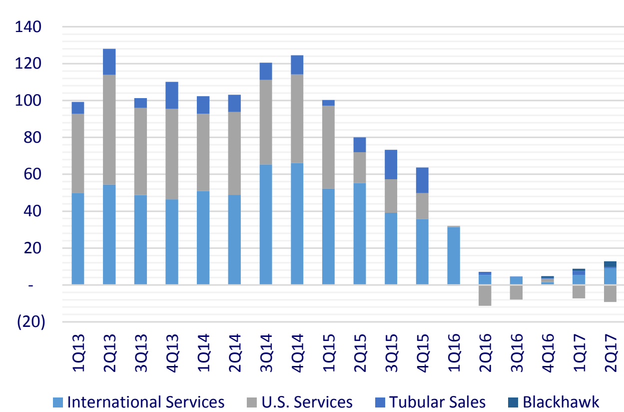
Source: Deutsche Bank

Figure 343: US Services mix between onshore and offshore



Source: Company reports, Deutsche Bank

Figure 344: EBITDA mix

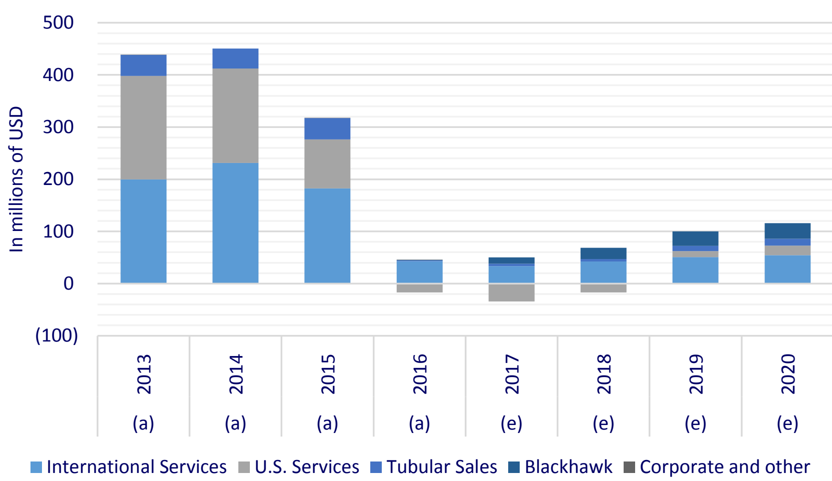


Source: Company reports, Deutsche Bank

US is a highly fragmented market

While US onshore activity is improving, the company is exploring business models for the US where FI is more of a rental company than a full service provider. The US is seeing a downshift in the number of hole sizes in horizontal wells, and many of the leading land drillers are taking share in the onshore TRS business. Land drillers feel like they have been cut out of the value chain, thus one of the disciplines that makes sense for them to onboard onto their rigs is TRS. FI is making proposals to some of the onshore players to rent them the equipment. This would be a lower revenue business model, but rentals have higher margins because personnel can be 40% of a full service ticket, but are low margin.

Figure 345: Segment EBITDA

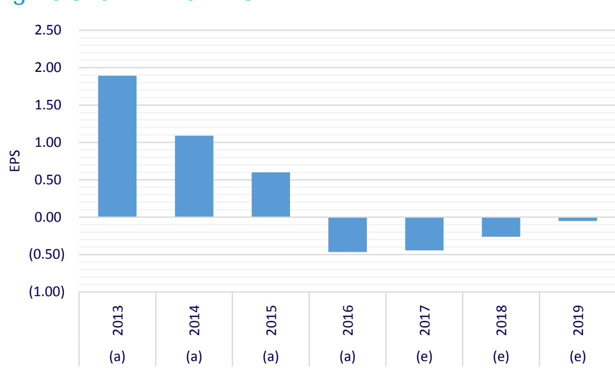


Source: Company reports, Deutsche Bank

Investing in Blackhawk business and expanding international market share

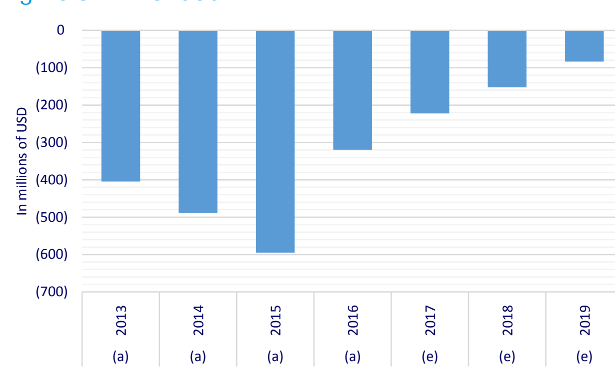
FI's focus now is to grow its market share internationally and to invest in its Blackhawk business. The company does not intend to do M&A in US onshore TRS, but instead wants to look for growth outside of its flagship TRS business. Its most recent initiative is the launch of a new frac plug from Blackhawk. The US is about 85% of Blackhawk revenues.

Figure 346: Annual EPS



Source: Company reports, Deutsche Bank

Figure 347: Net debt



Source: Company reports, Deutsche Bank

Figure 348: Income Statement

	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:							
International Services	475	537	442	237	212	229	262
U.S. Services	435	440	326	153	118	127	148
Tubular Sales	167	176	206	88	66	69	79
Blackhawk	0	0	0	10	80	110	140
Total revenue	1,078	1,153	975	488	476	535	629
Segment EBITDA:							
International Services	200	231	182	43	33	43	51
U.S. Services	198	181	94	(17)	(34)	(17)	12
Tubular Sales	41	38	41	2	5	5	10
Blackhawk	0	0	0	1	12	21	28
Corporate and other	0	(0)	0	0	0	0	0
Total EBITDA	439	450	317	30	16	52	100
D&A	78	90	109	114	120	106	96
EBIT	361	360	208	(85)	(105)	(55)	4
Interest (expense)	(1)	0	0	2	3	2	1
Interest income	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	0	0
Other income	(13)	(43)	(31)	(30)	(23)	(19)	(20)
PBT	347	318	177	(112)	(125)	(72)	(14)
Income tax (expense)	(39)	(76)	(50)	9	26	14	3
Non-controlling interest	(40)	(70)	(27)	21	0	0	0
Preferred dividends	0	0	0	0	0	0	0
Net income (operating)	268	172	101	(82)	(99)	(58)	(11)
Discontinued ops	43	0	0	0	0	0	0
Unusual after-tax	0	(13)	(22)	(38)	0	0	0
Net income (GAAP)	**311**	**159**	**79**	**(121)**	**(99)**	**(58)**	**(11)**
Reconciliation for NCI	33	55	25	0	0	0	0
Operating EPS	**1.89**	**1.09**	**0.60**	**(0.47)**	**(0.45)**	**(0.26)**	**(0.05)**
GAAP EPS	2.16	1.03	0.50	(0.68)	(0.45)	(0.26)	(0.05)
DPS	0.08	0.45	0.60	0.45	0.30	0.30	0.30
Diluted shares	159	208	209	176	223	223	223
EBITDA margin	40.7%	39.1%	32.6%	6.1%	3.3%	9.6%	16.0%
EBIT margin	33.5%	31.3%	21.4%	-17.4%	-21.9%	-10.2%	0.7%
Tax rate	11.2%	23.9%	28.1%	8.2%	20.8%	19.0%	19.0%

Source: Deutsche Bank

Figure 349: Cash Flow Statement

	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	268	172	101	(82)	(99)	(58)	(11)
Depreciation	78	90	109	114	120	106	96
Deferred tax	4	30	5	(28)	(20)	0	0
Chg in receivables	(82)	(43)	141	70	(17)	(14)	(43)
Chg in inventories	(82)	(30)	42	27	(5)	1	(34)
Chg in payables	3	5	(3)	(3)	1	(0)	5
Other	88	146	34	(109)	19	16	48
Cash from operations	277	369	428	(11)	(1)	50	61
Capital expenditures	(185)	(173)	(100)	(42)	(40)	(53)	(63)
Free cash flow	93	196	328	(53)	(41)	(3)	(2)
Acquisitions	0	0	(79)	(150)	0	0	0
Asset sales	51	1	5	4	2	0	0
Dividends paid	(117)	(69)	(93)	(79)	(67)	(67)	(67)
ESPP | options	0	0	0	1	1	0	0
Equity issuance, net	712	0	0	0	0	0	0
Debt issuance, net	(472)	(0)	(1)	(7)	(0)	0	0
Other	(15)	(43)	(48)	2	8	0	0
Chg in cash	252	84	113	(283)	(97)	(70)	(69)

Source: Deutsche Bank

Figure 350: Balance Sheet

	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	405	489	602	320	223	153	84
Accounts receivable	365	391	246	167	178	193	236
Inventories	186	204	161	139	145	145	179
Other current assets	16	23	14	14	17	18	22
Total current assets	971	1,107	1,024	640	564	508	520
Net PP&E	511	580	625	567	492	439	406
Goodwill	15	14	25	256	251	251	251
Other assets	64	57	54	125	126	129	137
Total assets	1,561	1,759	1,728	1,588	1,432	1,327	1,314
Accounts payable	22	16	13	16	21	21	26
Current debt	0	0	7	0	0	0	0
Other current liabilities	153	190	170	83	87	94	115
Total current liabilities	176	207	190	99	109	115	141
Long-term debt	0	0	0	0	0	0	0
Other LT liabilities	287	339	325	177	169	182	222
Shareholders' equity	1,098	1,213	1,213	1,311	1,154	1,029	951
Total liabilities and equity	1,561	1,759	1,728	1,588	1,432	1,327	1,314
Total debt	0	0	7	0	0	0	0
Net debt	(405)	(489)	(595)	(319)	(223)	(153)	(83)
Debt/capital	0%	0%	1%	0%	0%	0%	0%
Debt/equity	0%	0%	1%	0%	0%	0%	0%
Debt turns	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Halliburton

Reuters	Bloomberg
HAL.N	HAL US

David Havens
Research Analyst
+1-212-250-3235
david.havens@db.com

Price at 5 Oct 2017 (USD)	45.09
Price target	54.00
52-week range	58.21 - 38.66

Leadership in US Frac Best Practices

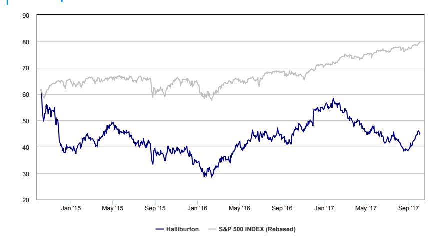
Initiating coverage with a Buy rating and a $54 price target

Halliburton offers liquidity in one of the few growing oilfield service markets, US pressure pumping. Service intensities continue to increase as pads get larger, average laterals continue to increase, the number of frac stages rises and more frac horsepower gets tied up on pads for longer. While we believe stubbornly low oil prices will be a headwind for the US rig count, the pressure pumping market is undersupplied despite capacity racing back into the market. Pricing should continue to improve through year-end, but at a moderate pace. 2018 should benefit from rising volumes as the industry begins to arrest the ascent of DUCs being inventoried due to the lack of frac crews. Importantly, we are encouraged that the earnings outlook has been reset lower after a period of irrational earnings assessments so early in the cycle.

The macro needs to kick-in for the stock to break out above $54 again

While the undersupplied US frac market is restoring HAL's earnings power, the international markets are struggling to catch volumes and pricing. Other than the Middle East, activity has remained depressed, and without a broader international uplift in 2019 and beyond, we expect the stock will encounter headwinds above $54.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	16.1	3.3	1.3
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	39,293.7
Shares outstanding (m)	871.5
Free float (%)	100
Volume (5 Oct 2017)	1,801,894
Option volume (und. shrs., 1M avg.)	2,775,042

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.07	0.04A	0.49
2Q EPS	-0.14	0.27A	0.53
3Q EPS	0.01	0.37	0.58
4Q EPS	0.04	0.47	0.62
FY EPS (USD)	-0.02	1.14	2.22
OLD FY EPS (USD)	-0.02	1.10	2.80
% Change	-0.0%	3.9%	-20.7%
P/E (x)	–	39.5	20.3
DPS (USD)	0.72	0.72	0.72
Dividend Yield (%)	1.7	1.6	1.6
Revenue (USDm)	15,887.0	19,588.5	21,381.3

Source: Deutsche Bank estimates, company data

Valuation

Our $54 price target is 16.3x our estimate of the company's normalized EPS power of $3.30 per share, which is one standard deviation above its average five-year multiple of 13.2x leading up to the 2014 collapse in oil prices. We expect as the relatively unique momentum in the US frac market continues in 2018, HAL's leverage to this market will continue to make it a core holding in the group, especially as investors are mindful of trading liquidity in an otherwise volatile market. We expect resistance at $53 though as US drilling has limited upside in our view due to stubbornly low oil prices in 2018.

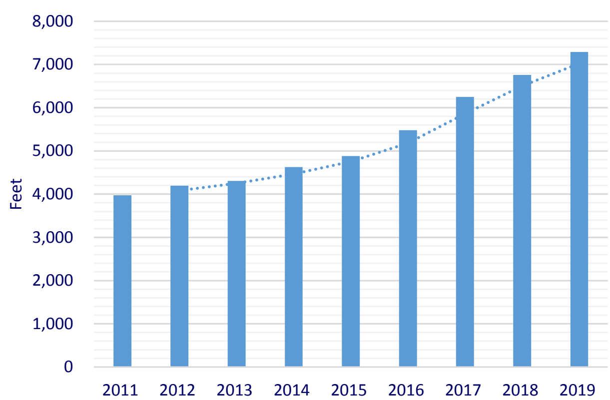
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a deferral of completions on DUCs due to lower oil prices, 4) a rapid acceleration in frac newbuilds in the US that deflate pricing, and 5) a materially weaker international market.

Key investment themes

Longer laterals to drive further service intensity in the US

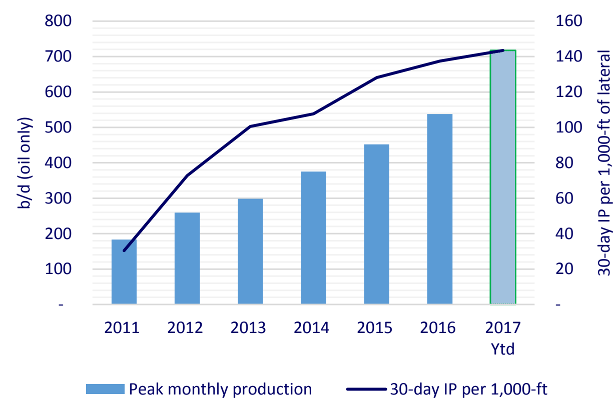
While we are seeing gains in the average 30-day IP per 1,000-ft of lateral slow after years of substantial increases, producers are still extending the overall lateral lengths. For years we have all questioned the industry on the technical and economic limits of horizontal laterals. Since 2011, the average lateral length has increased by 40% to 6,000-ft. The leading edge is up to 12,000-ft with some experimenting with 20,000+ feet. So far the limitations have been related to limits on friction reducing agents, availability of continuous acreage capable of accommodating longer laterals, and risk. Risk because laterals are drilled open-hole, not cased hole. When laterals extend out to 12,000-ft, costs escalate as does the risk of well integrity. Some smaller, less sophisticated producers are unwilling to take on that risk. But we found that over the last three years, about 50% of the wells placed on production in the Permian and Eagle Ford were drilled by one of the top 30 most active producers, the vast majority of which are pressing ahead with longer laterals.

Figure 351: Average Permian horizontal lateral lengths



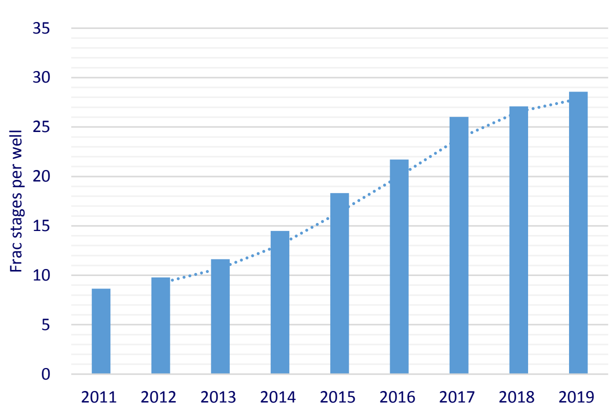
Source: IHS Markit

Figure 352: Average Permian 30-day IPs per 1,000-ft



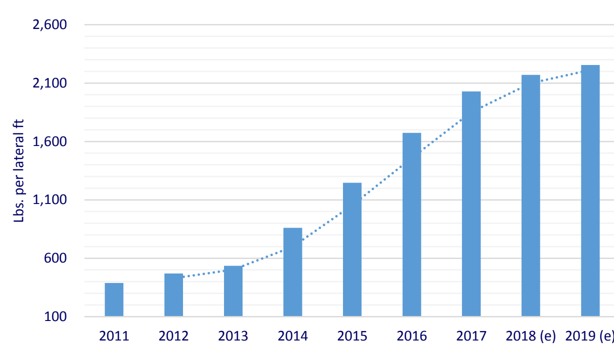
Source: Deutsche Bank

Figure 353: Permian frac stages per well



Source: IHS Markit

Figure 354: Permian sand volumes per lateral foot

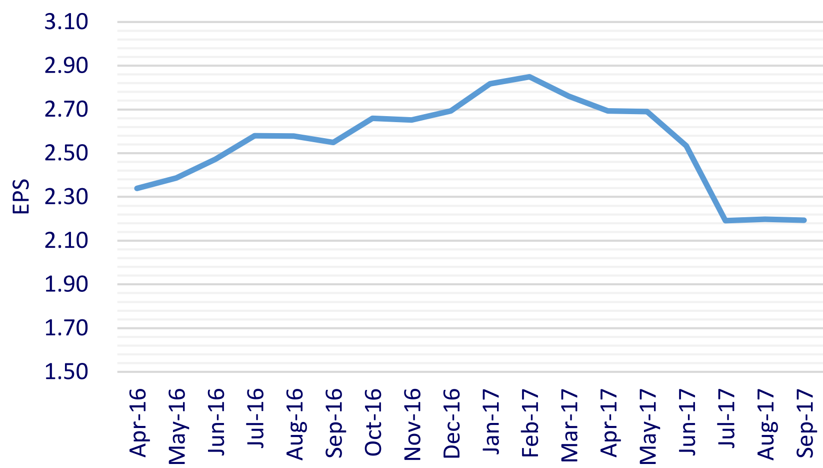


Source: IHS Markit

Earnings revisions have acknowledged a more realistic outcome now

What discouraged us and kept our long-standing negative view on the stocks intact was the rapid rise in earnings expectations following the recovery in the US rig count. While standard operating procedure, it showed the market had not acknowledged any shift in market dynamics due to the disruption from tight oil development. Earnings, particularly in HAL, have since reset lower, presenting a much better setup in the stock.

Figure 355: HAL 2018 consensus EPS revisions

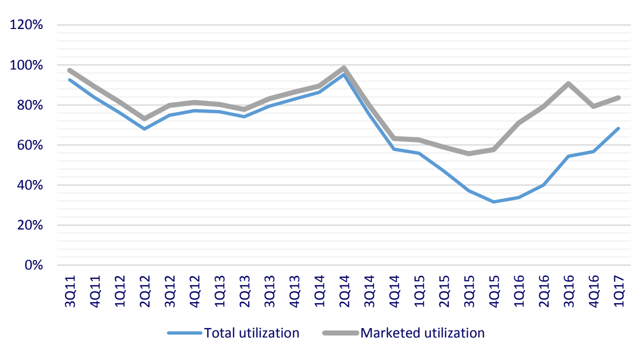


Source: Factset

US pressure pumping market is undersupplied

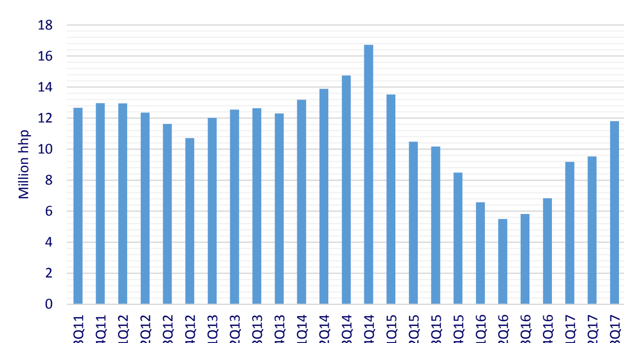
The positive supply/demand trends are continuing in the frac market, driven by a rising well count, increased pad drilling, more wells per pad and an increasing inventory of DUCs (drilled but uncompleted wells). Frac fleets are also incorporating more hhp, averaging about 50k now. The increase is to accommodate the larger pads, which are keeping crews on location longer, thus in order to accommodate maintenance rotations and suitable uptime, contractors have increased fleet sizes.

Figure 356: Total vs. marketed frac hhp utilization



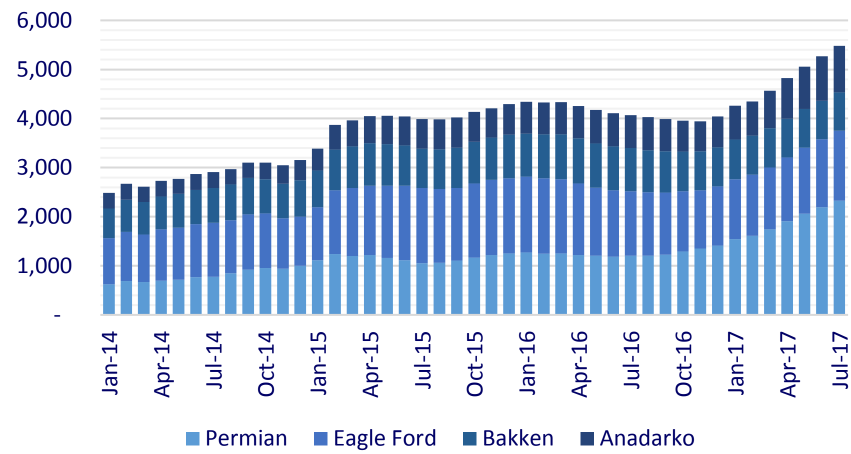
Source: IHS Markit, Deutsche Bank

Figure 357: US frac hhp demand



Source: IHS Markit, Deutsche Bank

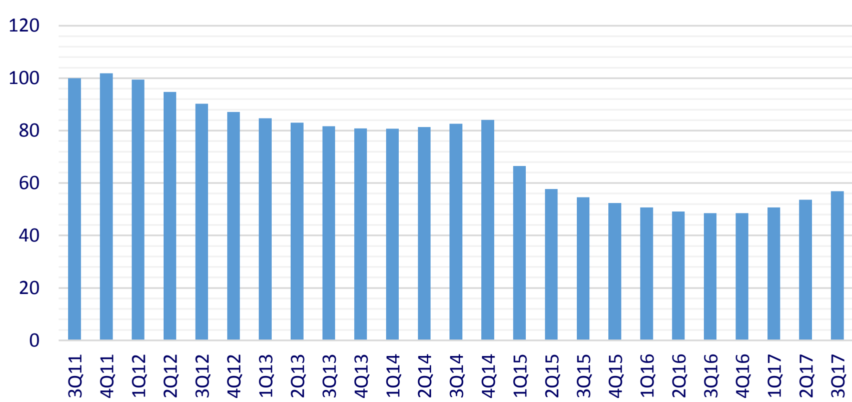
Figure 358: DUCs are building as frac horsepower is sold out



Source: EIA

HAL is reactivating idle equipment at leading edge rates while its in-house manufacturing is providing a competitive advantage with newbuild lead times of about one month versus the industry at about 9-12 months. HAL has not yet committed to any newbuilds, but the company's calendar is sold out through year-end. Industry demand has recovered to about 12 million hhp versus 17 million at the peak, and less than 6 million at the trough. All available horsepower by and large is now booked through year-end 2017. Marketed utilization is back above 80% with some contractors suggesting the market is undersupplied by 1.5 – 2.0 million horsepower.

Figure 359: US frac pricing indexed to 3Q11



Source: IHS Markit, Deutsche Bank

Pricing moving higher, albeit more modestly

Pricing has improved, but more moderately than what some producers had previously expected. While several contractors are suggesting pricing is not yet at newbuild economics, HAL does believe the economics are there, but has not yet committed. We view HAL should benefit from the fact that its fleet pricing will all rollover to market prices within a year.

Attrition is increasing

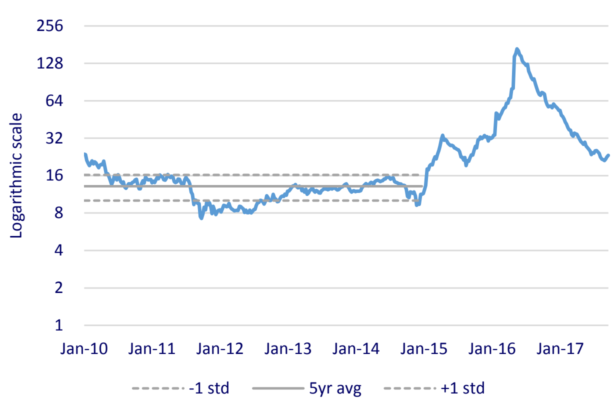
Frac intensity on the larger pads and bigger wells is chewing equipment faster than last cycle, kicking attrition into a higher gear. Industry expectations for attrition are upwards of 3.5 million hhp per annum as useful lives decline and maintenance capital rises. While this is tightening the market upfront, it increases the capital intensity for the industry longer term.

Valuation and risks

Our $54 price target is 16.3x our estimate of the company's normalized EPS power of $3.30 per share, which is one standard deviation above its average five-year multiple of 13.2x leading up to the 2014 collapse in oil prices. We expect as the relatively unique momentum in the US frac market continues in 2018, HAL's leverage to this market will continue to make it a core holding in the group, especially as investors are mindful of trading liquidity in an otherwise volatile market. We expect resistance at $53 though as US drilling has limited upside in our view due to stubbornly low oil prices in 2018.

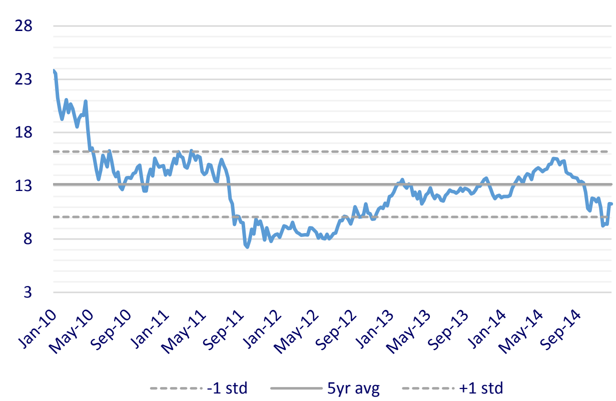
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a deferral of completions on DUCs due to lower oil prices, 4) a rapid acceleration in frac newbuilds in the US that deflate pricing, and 5) a materially weaker international market.

Figure 360: The P/E valuation band has blown out



Source: Factset

Figure 361: The 5yr P/E leading up to 2014



Source: Factset

Company description

Halliburton (HAL) is a leading multi-national oilfield services company with a particularly strong presence in the US. At the peak of the last cycle, the company generated $16.8 billion of revenue from the US, making it the single largest oilfield service provider in the country, and representing about 51% of its total 2014 revenues. Its Middle East/Asia geomarket was its second largest source of revenues at $5.8 billion, or 18% of total 2014 revenues.

The company has two reporting segments including Completion & Production (C&P) and Drilling & Evaluation (D&E). Over half of its revenues come from C&P, which includes HAL's industry leading hydraulic fracturing and cementing businesses. In D&E, Halliburton is top two in drilling fluids with its Baroid business, directional drilling with its Sperry Drilling business, and wireline. HAL prides itself on being the execution company and strives to structurally lower both its own cost structure as well as for its customers and raise efficiencies by leveraging its scale and vertical integration.

Figure 362: Reporting segments

Halliburton Co.

Completion & Production

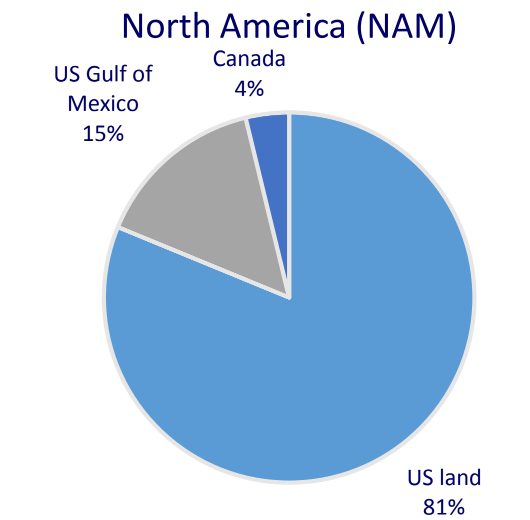
- Production Enhancement
  - Stimulation
    - Hydraulic Fracturing
    - Acidizing
  - Sand Control Services
  - Microseismic
- Cementing (zonal isolation)
  - Cementing Services
  - Casing Equipment
- Completion Tools
  - Intelligent Well Completions
  - Liner Hanger Systems
  - Sand Control Systems
- Production Solutions and Well Intervention
  - Coiled Tubing
  - Workover and Snubbing Units
  - Thru Tubing Tools
  - Slickline
- Pipeline and Process Services
  - Pre-commissioning and commissioning
  - Maintenance and Decommissioning
  - Onshore and Offshore
- Chemical Services
  - Production Chemicals
  - Stimulation Chemicals
  - Midstream Solutions
- Artificial Lift
  - Electric Submersible Pumps (ESP)
  - Progressive Cavity Pumps (PCP)
  - Remote Monitoring and Control

Drilling & Evaluation

- Baroid
  - Drilling and Completion Fluids
  - Solids Control Equipment and Services
  - Performance Additives
  - Waste Management
- Sperry Drilling
  - Directional Drilling
  - Downhole Tools
  - Geosteering Services
  - Measurement-while Drilling (MWD)
  - Logging-while-Drilling (LWD)
  - Surface Data Logging
  - Managed Pressure and Underbalanced
- Drill Bits and Services
  - Drill Bits
  - Coring Equipment
- Wireline and Perforating
  - Formation Evaluation (open-hole logging)
  - Cased-hole and Slickline Services
    - Perforating
    - Pipe recovery (fishing)
  - Well Assurance (integrity)
  - Plug and Abandonment
- Landmark Software and Services
  - Integrated Software and Data Management
- Consulting and Project Management
- Reservoir Testing and Analysis
  - Drillstem Testing
  - Fluid Sampling
  - Surface Well Testing

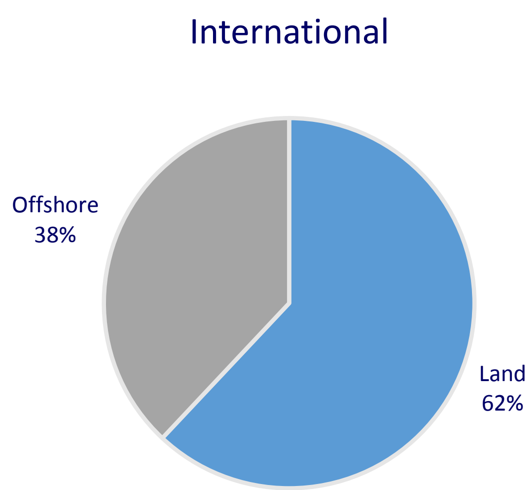
Source: Company reports

Figure 363: HAL 2016 North America revenue mix



Source: Company reports, Deutsche Bank

Figure 364: HAL 2016 international revenue mix



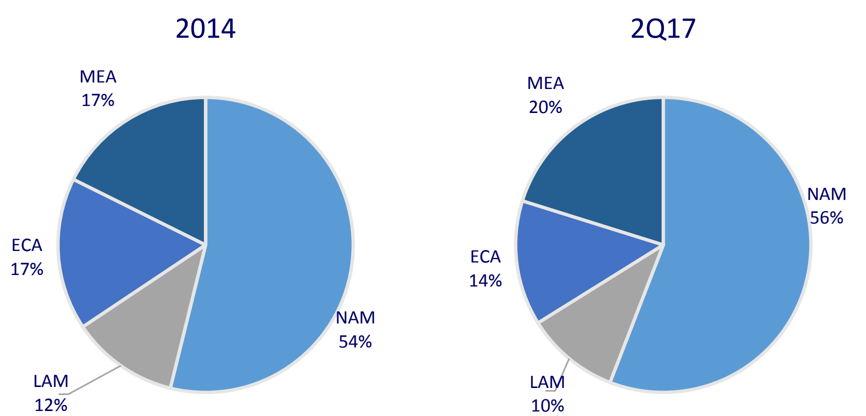
Source: Company reports, Deutsche Bank

Principal Sources and Uses of Cash Flow

The US is Halliburton's principal market

HAL generates an increasingly larger portion of its revenue from North America versus its peers given its leading position in that market and the cyclical recovery. For the past three years, the US itself has made up between 40-51% of total revenues for HAL, while no other individual country accounted for more than 10%. In terms of regions, North America peaked at 60% of total revenue in 1Q12 before briefly falling below 40% in 2Q16 as the downturn weighed on activity levels. As the NAM cyclical recovery accelerated and given the headwinds and seasonality of its International operations in the first quarter, NAM accounted for 52% of total revenue in 1Q17, and then 56% in 2Q17.

Figure 365: Revenue mix by region



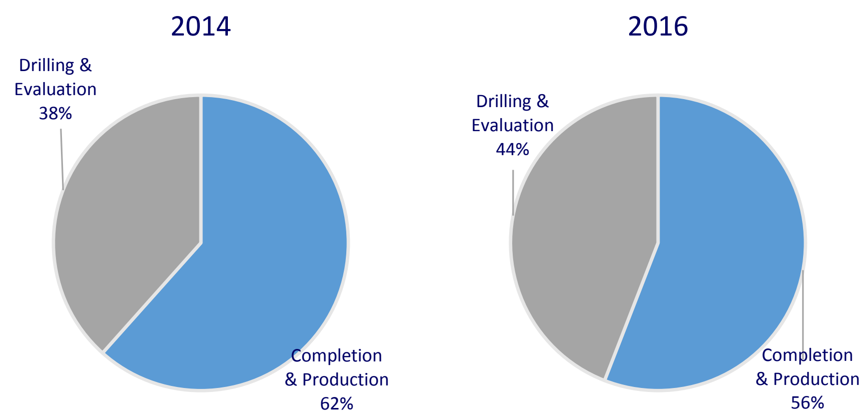
Source: Deutsche Bank

HAL spent a lot of the 2000s building out its international footprint and leveraging its scale and product portfolio to be able to compete for integrated project management tenders globally. Middle East/ Asia averaged around 18% of total revenue over the past 10 years but had grown to 27% in 2016 as the Middle East was more resilient in terms of activity and spending during the downturn and HAL gained some market share in the region. Europe/ Africa/ CIS is the next largest region accounting for about 20% of total revenue, but had slipped slightly to 19% in 2016. Lastly, Latin America has averaged around 13% of total revenue with 2016 averaging closer to 12%.

Strategy is to leverage its vertical integration

HAL's strategy is focused around driving down costs for their customers while also improving reservoir productivity and customer operational efficiencies. The company seeks to increase equipment utilization and manage costs through expanding its surface efficiency model. It leverages its vertical integration to build new capacity at a lower cost than having to order it through an outside manufacturer and being able to wait longer to see how the cycle develops before building new capacity. Its ultimate goal is to pursue an asset light model that will be able to adjust to what they company believes will be shorter cycles in North America. HAL also looks to leverage its scale, technological capabilities, depth and breadth of product lines, and global infrastructure to win integrated project management work internationally.

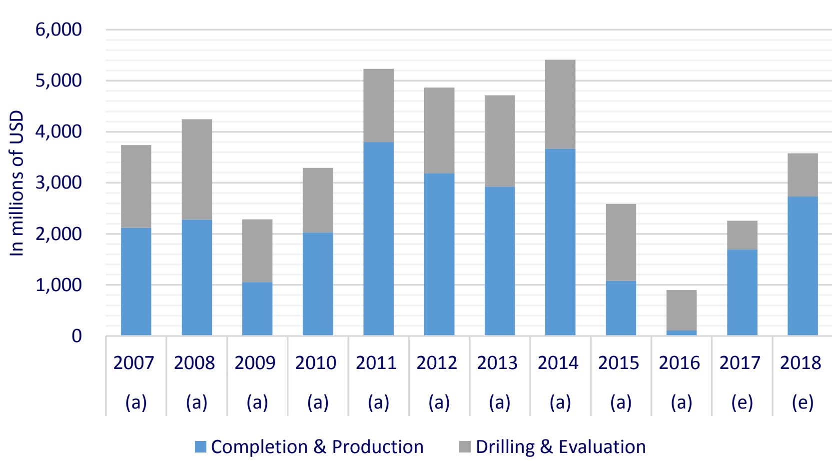
Figure 366: Revenue mix by reporting segment



Source: Company reports, Deutsche Bank

HAL's strategy shifted early on in the US recovery as the company decided to leverage its leading US position by reactivating equipment faster than originally expected in order to win back market share. This part of the business is driven by the rig and well count in the US, customer spend, pricing, and utilization of its pressure pumping and related services business lines. C&P margins should continue to improve moving forward and start to contribute more to the company's overall operating income as customer spending on completions continues to increase. Given the lag in international markets compared to the US recovery, the impact from pricing pressures as older contracts roll off, and in general more offshore weighted markets, headwinds should remain in international spending and activity in our view.

Figure 367: EBIT trends by reporting segment

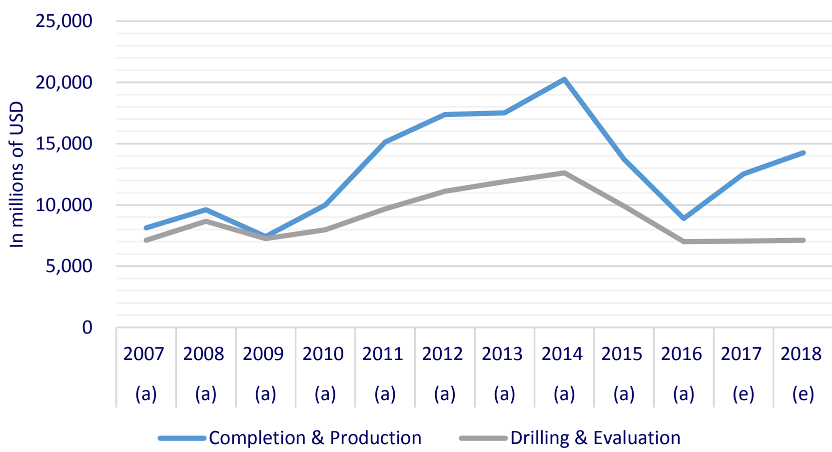


Source: Company reports, Deutsche Bank

HAL's asset exposure is heavily weighted to the US

HAL is the second largest diversified oilfield services provider and operates in approximately 70 countries, but has about half of its PP&E in the US. The company's C&P segment is focused on cementing, stimulation, intervention, pressure control, specialty chemicals, artificial lift, and completion services. Drilling and Evaluation (D&E) provides field and reservoir modeling, drilling, wellbore placement solutions, and well construction. Baroid (drilling fluids), Sperry Drilling (drilling systems), and Landmark software are some of the business lines inside its D&E segment.

Figure 368: Annual segment revenues



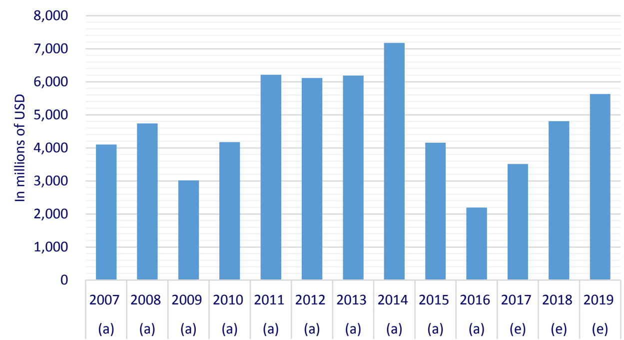
Source: Company reports, Deutsche Bank

C&P revenues were down 35% y/y in 2016 due to a decline in activity and pricing across the majority of the individual product lines in the segment but NAM pressure pumping drove the majority of the decline. International revenue decreased due to lower well completion services and stimulation in all regions. C&P operating income was $107mm in 2016 down from $1.1bn in 2015 due to similar reasons that caused the revenue decline in the segment.

D&E revenues were down 30% y/y in 2016 due to lower rig counts, customer spending, and pricing. D&E operating income was $794mm in 2016, down from $1.5bn in 2015 due to similar reasons that caused the revenue decline. HAL called out lower drilling and logging activity in the Middle East/ Asia region and reduced fluid services in Latin America. D&E revenue and operating income margins did not fall as far as C&P did as it is more internationally weighted which tends to have less cyclicality than North America given its longer contract terms and more project management oriented work.

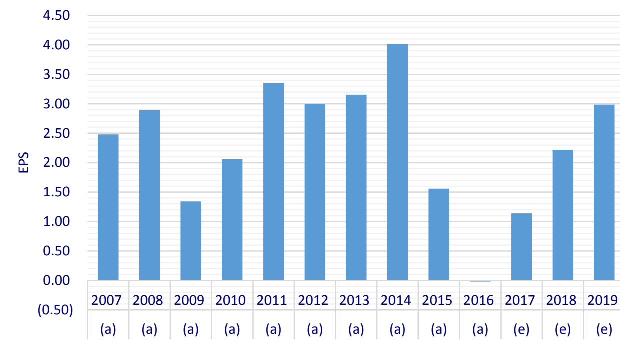
Inside these businesses in its two segments, HAL has a leading position in many of the individual product lines. HAL is known for its cementing, given that is how the company got its start, so Spears & Associates estimates that HAL is the market leader in cementing with about 40% global market share. In hydraulic fracturing, HAL is also the market leader at about 30% market share. In other completion related product lines HAL generally has a top 3 position. In its drilling product portfolio, HAL also generally holds a top 2 or 3 position in those product lines.

Figure 369: Consolidated EBITDA



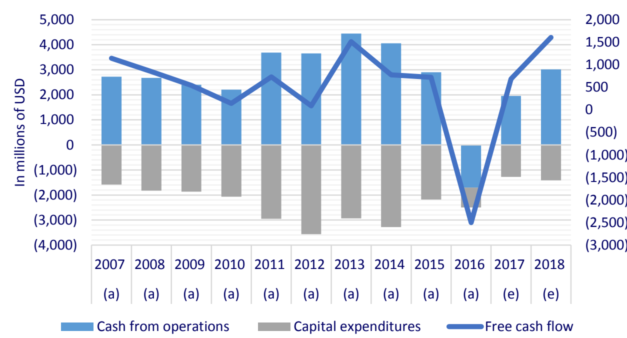
Source: Company reports, Deutsche Bank

Figure 370: Annual EPS



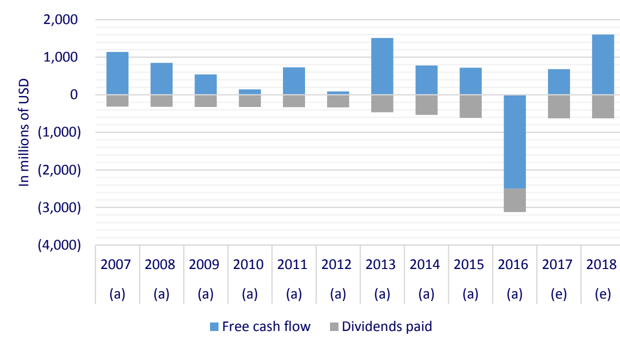
Source: Company reports, Deutsche Bank

Figure 371: Free cash flow and capex



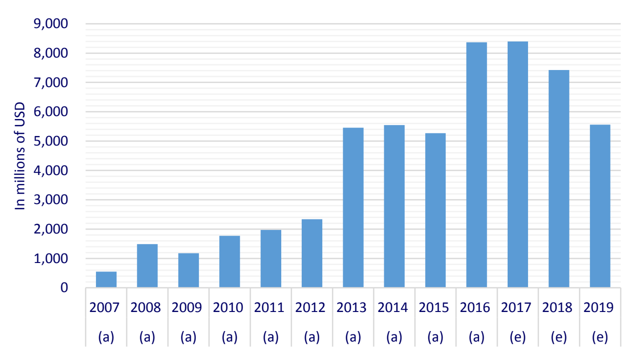
Source: Company reports, Deutsche Bank

Figure 372: Free cash flow and dividends



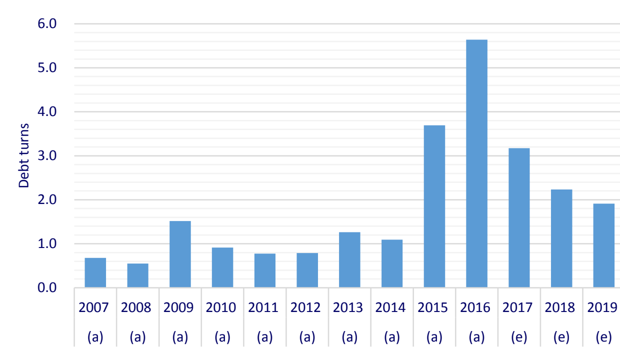
Source: Company reports, Deutsche Bank

Figure 373: Net debt



Source: Company reports, Deutsche Bank

Figure 374: Debt turns



Source: Company reports, Deutsche Bank

Figure 375: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Completion & Production	7,419	9,997	15,143	17,380	17,506	20,253	13,721	8,882	12,536	14,258	14,843
Drilling & Evaluation	7,256	7,976	9,686	11,123	11,896	12,617	9,912	7,005	7,052	7,124	7,416
Total revenues	14,675	17,973	24,829	28,503	29,402	32,870	23,633	15,887	19,588	21,381	22,259
Segment EBIT:											
Completion & Production	1,056	2,032	3,800	3,192	2,925	3,670	1,082	107	1,696	2,732	3,270
Drilling & Evaluation	1,231	1,263	1,431	1,675	1,789	1,740	1,506	794	560	845	1,139
Corporate G&A	(205)	(236)	(377)	(380)	(429)	(362)	(267)	(210)	(278)	(280)	(280)
Total EBIT	2,082	3,059	4,854	4,487	4,285	5,048	2,321	691	1,979	3,297	4,129
Interest (expense)	(297)	(308)	(268)	(301)	(331)	(383)	(410)	(527)	(501)	(480)	(476)
Interest income	12	11	5	5	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	(27)	(26)	(25)	(41)	(43)	0	(125)	(208)	(96)	(70)	(47)
PBT	1,770	2,736	4,566	4,150	3,911	4,665	1,786	(44)	1,382	2,748	3,606
Income tax (expense)	(547)	(850)	(1,468)	(1,355)	(1,057)	(1,243)	(449)	22	(387)	(811)	(1,001)
Non-controlling interest	(10)	(7)	(5)	(10)	(10)	(1)	(4)	6	0	0	0
Net income (operating)	1,213	1,879	3,093	2,785	2,844	3,421	1,333	(16)	995	1,937	2,605
Discontinued ops	(9)	40	(166)	58	19	64	(5)	(2)	0	0	0
Unusual after-tax	(60)	(84)	(88)	(208)	(738)	15	(1,999)	(6,126)	(271)	0	0
Net income (GAAP)	**1,144**	**1,835**	**2,839**	**2,635**	**2,125**	**3,500**	**(671)**	**(6,144)**	**723**	**1,937**	**2,605**
Operating EPS	**1.34**	**2.06**	**3.35**	**3.00**	**3.15**	**4.02**	**1.56**	**(0.02)**	**1.14**	**2.22**	**2.99**
GAAP EPS	1.27	2.01	3.08	2.84	2.36	4.11	(0.79)	(7.13)	0.83	2.22	2.99
DPS	0.36	0.36	0.36	0.36	0.53	0.66	0.72	0.72	0.72	0.72	0.72
Diluted shares	902	911	922	928	902	851	854	862	871	872	872
EBITDA	**3,013**	**4,178**	**6,213**	**6,115**	**6,185**	**7,174**	**4,156**	**2,194**	**3,514**	**4,810**	**5,629**
EBITDA margin	20.5%	23.2%	25.0%	21.5%	21.0%	21.8%	17.6%	13.8%	17.9%	22.5%	25.3%
EBIT margin	14.2%	17.0%	19.5%	15.7%	14.6%	15.4%	9.8%	4.3%	10.1%	15.4%	18.5%
Tax rate	30.9%	31.1%	32.2%	32.7%	27.0%	26.6%	25.2%	50.0%	28.0%	29.5%	27.8%

Source: Deutsche Bank

Figure 376: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	1,213	1,879	3,093	2,785	2,844	3,421	1,333	(16)	995	1,937	2,605
Depreciation	931	1,119	1,359	1,628	1,900	2,126	1,835	1,503	1,535	1,513	1,500
Deferred tax	274	124	(30)	0	0	0	0	0	(216)	0	0
Chg in receivables	869	(902)	(1,218)	(682)	(449)	(1,375)	1,468	899	(554)	(216)	(109)
Chg in inventories	232	(331)	(564)	(611)	327	(247)	153	552	120	(46)	46
Chg in payables	(118)	330	649	200	(107)	489	(603)	(219)	362	45	(45)
Other	(995)	(7)	395	334	(68)	(352)	(1,280)	(4,422)	(281)	(215)	(40)
Cash from operations	2,406	2,212	3,684	3,654	4,447	4,062	2,906	(1,703)	1,961	3,018	3,956
Capital expenditures	(1,864)	(2,069)	(2,953)	(3,566)	(2,934)	(3,283)	(2,184)	(798)	(1,275)	(1,410)	(1,468)
Free cash flow	542	143	731	88	1,513	779	722	(2,501)	686	1,607	2,488
Acquisitions	(55)	(523)	(880)	(214)	(94)	(231)	(39)	(31)	0	0	0
Asset sales	203	0	0	395	241	0	168	222	76	0	0
Dividends paid	(324)	(327)	(330)	(333)	(465)	(533)	(614)	(620)	(626)	(628)	(628)
ESPP | options	30	0	160	107	277	332	167	0	0	0	0
Equity issuance, net	(17)	(141)	(43)	(33)	(4,356)	(800)	0	186	0	0	0
Debt issuance, net	1,944	(790)	978	0	2,968	0	7,440	(3,097)	(1,391)	(400)	0
Other	(53)	295	181	(374)	(212)	388	(58)	(227)	(2)	0	0
Chg in cash	2,270	(1,343)	797	(364)	(128)	(65)	7,786	(6,068)	(1,257)	579	1,860

Source: Deutsche Bank

Figure 377: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	3,394	2,051	2,848	2,484	2,356	2,291	10,077	4,009	2,752	3,331	5,191
Accounts receivable	2,964	3,924	5,084	5,787	6,181	7,564	5,317	3,922	4,324	4,541	4,650
Inventories	1,598	1,940	2,570	3,186	3,305	3,571	2,417	2,275	2,158	2,204	2,158
Deferred taxes	210	257	321	0	0	0	0	0	0	0	0
Other current assets	472	714	754	1,629	1,862	1,642	3,798	1,471	1,524	1,601	1,639
Total current assets	8,638	8,886	11,577	13,086	13,704	15,068	21,609	11,677	10,759	11,676	13,638
Net PP&E	5,759	6,842	8,492	10,257	11,322	12,475	10,911	8,532	8,291	8,188	8,157
Goodwill	1,100	1,315	1,776	2,135	2,168	2,330	2,109	2,414	2,407	2,407	2,407
Other assets	1,041	1,254	1,832	1,932	2,029	2,367	2,313	4,377	4,495	4,719	4,833
Total assets	16,538	18,297	23,677	27,410	29,223	32,240	36,942	27,000	25,951	26,991	29,035
Accounts payable	787	1,139	1,826	2,041	2,365	2,814	2,019	1,764	2,130	2,176	2,130
Accrued expenses	514	716	862	930	1,029	1,033	838	544	612	642	658
Current debt	750	0	0	0	0	0	659	163	736	336	336
Other current liabilities	838	902	1,433	1,781	1,632	2,036	1,843	1,552	1,031	1,083	1,109
Total current liabilities	2,889	2,757	4,121	4,752	5,026	5,883	5,359	4,023	4,509	4,237	4,233
Long-term debt	3,824	3,824	4,820	4,820	7,816	7,840	14,687	12,214	10,416	10,416	10,416
Deferred taxes	0	0	0	0	0	0	0	0	0	0	0
Employee obligations	462	487	534	607	584	691	457	574	550	550	550
Other LT liabilities	606	842	986	1,441	2,182	1,528	944	741	984	1,033	1,058
Non-controlling int	29	14	18	25	34	31	33	39	36	36	36
Shareholders' equity	8,728	10,373	13,198	15,765	13,581	16,267	15,462	9,409	9,456	10,719	12,742
Total liabilities and equity	16,538	18,297	23,677	27,410	29,223	32,240	36,942	27,000	25,951	26,991	29,035
Total debt	4,574	3,824	4,820	4,820	7,816	7,840	15,346	12,377	11,152	10,752	10,752
Net debt	1,180	1,773	1,972	2,336	5,460	5,549	5,269	8,368	8,400	7,421	5,561
Debt/capital	34%	27%	27%	23%	37%	33%	50%	57%	54%	50%	46%
Debt/equity	52%	37%	37%	31%	58%	48%	99%	132%	118%	100%	84%
Debt turns	**1.5**	**0.9**	**0.8**	**0.8**	**1.3**	**1.1**	**3.7**	**5.6**	**3.2**	**2.2**	**1.9**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Helmerich & Payne

Reuters	Bloomberg
HP.N	HP US

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Price at 5 Oct 2017 (USD)	52.17
Price target	45.00
52-week range	81.63 - 42.34

Navigating an industry in transition

Initiating coverage with a Hold rating and a $45 price target

While we believe the company is an industry leader in terms of fleet quality, fiscal stability and free cash flow performance, the higher cadence of more productive wells being drilled in the US is undermining the earnings power of the company. HP is the closest to a pure play US land driller amongst its peers, and while the company is tactically taking market share, we believe pricing power in the US will be challenging as oil prices are confined to a range of $40 – 55 and the US rig count is confined to only 6% growth in 2018.

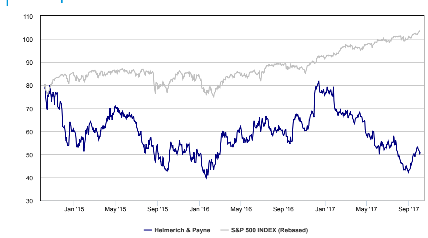
Management sees its competitive edge being its inventory of rig upgrades

While the peers are looking to reestablish themselves in the value chain by offering a broader suite of service content and technology, HP's ambition is market share. While the company is also actively investing in service content, its focus is on restoring its earnings power by upgrading at the lowest relative cost its industry leading inventory of 1,500hp AC-electric rigs to super-spec capabilities. The company has already added almost 500 basis points of market share, but as the market flattens out in 2018, as we expect it will, we believe the cadence of upgrades will slow and pricing power will ebb.

US Land earnings power downshifting from $1.5 billion to $0.9 billion

Drilling more with less has bifurcated the market and has created a challenging pricing environment for HP. We believe it is unreasonable to assume it can restore its daily margins to the $15,000 per day run rate even with its leading share in super-spec rigs. We expect $10,000 per day to be at the high-end over the next few years. Assuming gains to 25% US market share, that takes our US Land EBITDA best case up to $0.9 billion.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	18.9	-8.3	-21.1
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	5,660.2
Shares outstanding (m)	108.5
Free float (%)	100
Volume (5 Oct 2017)	346,654
Option volume (und. shrs., 1M avg.)	86,711

Source: Deutsche Bank

Forecasts and ratios

Year End Sep 30	2016A	2017E	2018E
1Q EPS	0.05	-0.41A	-0.21
2Q EPS	-0.28	-0.47A	-0.26
3Q EPS	-0.47	-0.25A	-0.21
4Q EPS	-0.33	-0.21	-0.12
FY EPS (USD)	-1.03	-1.34	-0.79
OLD FY EPS (USD)	–	–	–
% Change	–	–	–
P/E (x)	–	–	–
DPS (USD)	2.76	2.80	2.80
Dividend Yield (%)	5.0	5.4	5.4
Revenue (USDm)	1,405.3	1,737.8	2,001.0

Source: Deutsche Bank estimates, company data

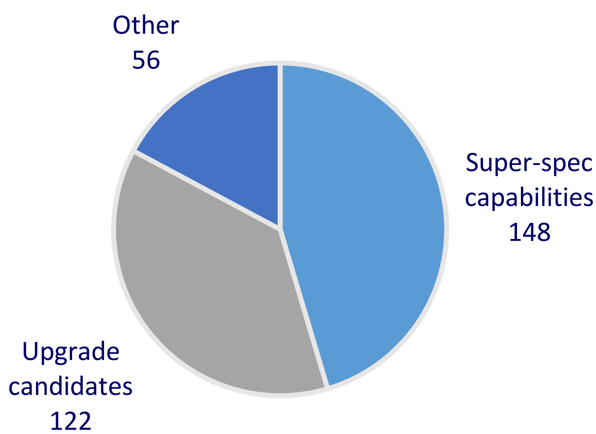
Valuation
Our $45 price target is 5.5x our estimate of the company's normalized EBITDA of $0.9 billion, which is in-line with the 5.5x five-year average multiple leading up to the 2014 collapse in oil prices. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a dividend cut, and 4) a step up in cost inflation in the US Land segment.

Key investment themes

Largest inventory of low cost upgrades to super-spec capabilities

Improved drilling efficiencies and enhanced completion designs have enabled US producers to drill a higher cadence of more productive wells using fewer rigs. This has undermined the earnings power of the land drilling industry and has forced its key players to devise strategies that will reestablish them in the value chain. For HP, market share is a core ambition. The company believes it can restore its earnings power by upgrading more rigs than any of its peers to the preferred super-spec rig capabilities at the lowest relative cost.

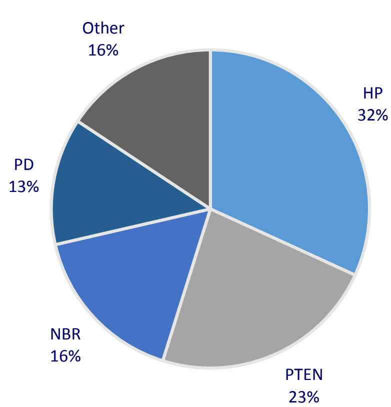
Figure 378: HP has 122 rig upgrade candidates in inventory



Source: Company reports

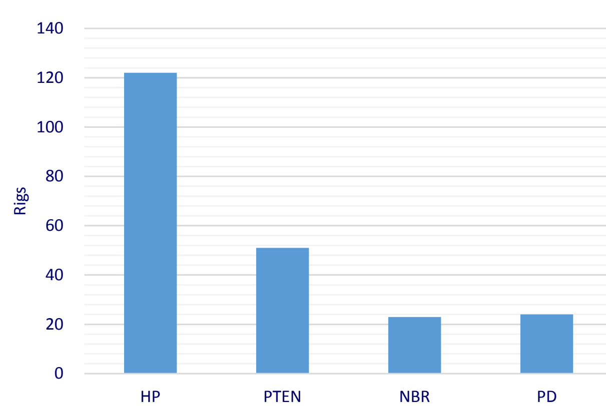
HP currently has 350 land rigs in the US, of which 326 are 1,500hp AC-electric FlexRigs. The company has upgraded 148 of these to super-spec capabilities for about $1-2 million apiece. Super-spec rigs are 1,500hp AC-electric rigs that are pad capable with 750,000 lb. hook loads, 7,500 psi mud systems with a third mud pump, a fourth engine and a 25,000-ft pipe racking capability.

Figure 379: US super-spec market share



Source: Company reports, Deutsche Bank

Figure 380: Inventory of super-spec upgrade candidates



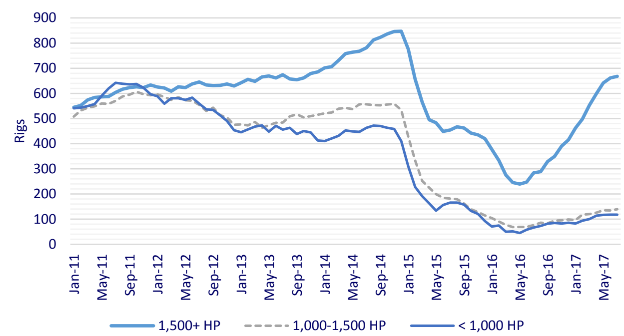
Source: Company reports, Deutsche Bank

HP has another 122 super-spec upgrade candidates, which is more than its three largest peers combined. The cost to upgrade as the company reaches deeper into its inventory is about $2-3 million each. The company does not intend to fund any more newbuilds in the current environment, but we do expect a cadence of 15-20 upgrades per quarter through early 2018.

Super-spec rigs are getting higher prices in select markets, but some friction

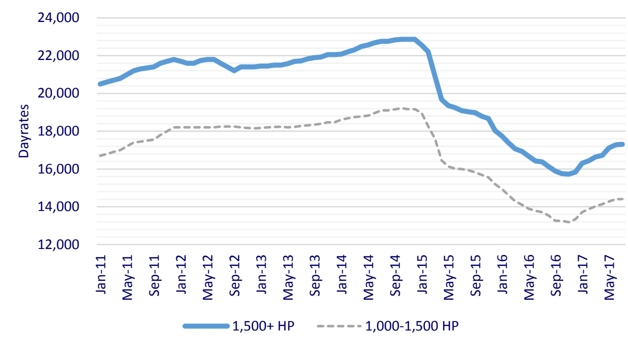
The drilling more with less trend has bifurcated the US land rig market and has eroded the marketability of mechanical and SCR rigs. Pricing power is now reserved for the 1,500hp AC-electric and super-spec rigs that enable the drilling efficiencies that are in high demand in the Permian, Eagle Ford and SCOOP/ STACK. Super-spec rigs in these regions are getting $2,000 more per day versus AC-electric rigs, and have achieved a leading edge rate of $20-22 kpd. But despite being above 90% utilization, super-spec pricing is flattening as the stream of upgraded capacity comes into a flattening market. We expect the ebb and flow of US capex and the rehabilitation of US productivity to confine oil prices to a range of $40 – 55 and the US rig count to a mere 6% growth in 2018. We believe this will make pricing a challenge.

Figure 381: A bifurcated market



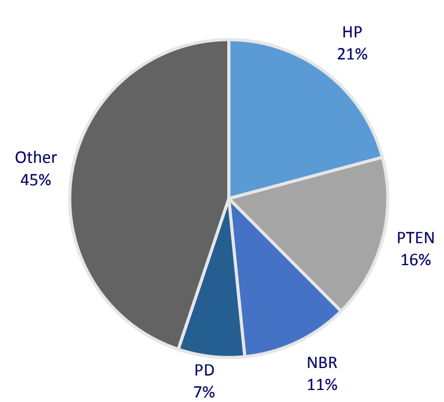
Source: Land Rig Newsletter

Figure 382: Pricing will be challenging in 2018



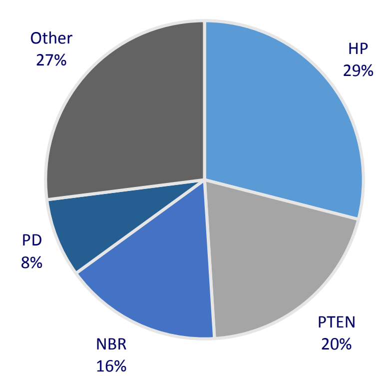
Source: Land Rig Newsletter

Figure 383: Total US land drilling market share



Source: Company reports, Baker Hughes, a GE company

Figure 384: Market share of AC-electric rigs

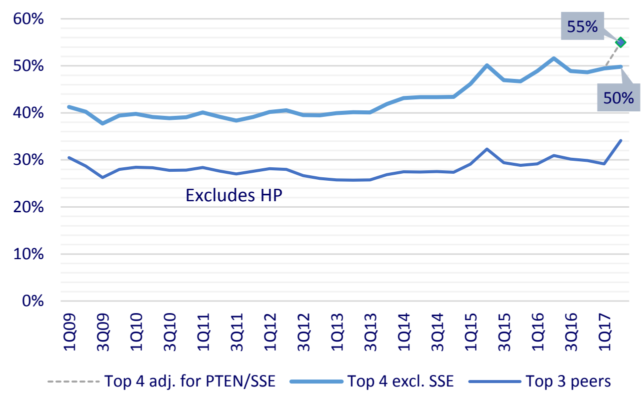


Source: Company reports

HP has taken almost 500 basis points of market share since the 2014 highs

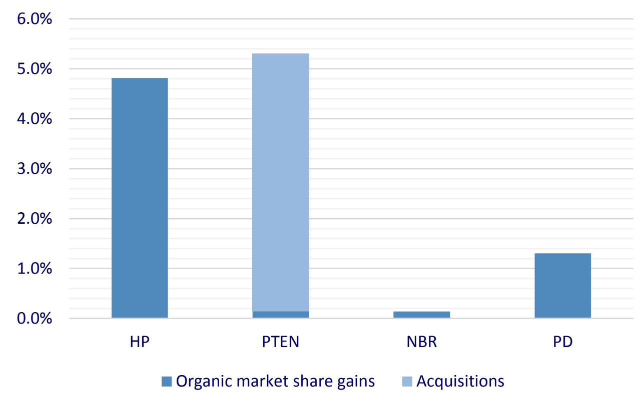
While the bifurcation of the US land drilling market should play right into the hands of the top four land drillers, HP has really been the primary driver of the group's market share gains. While high customer demand for technologies that enable improved drilling efficiencies prompted each of the top four to invest in improving rig functionality, HP had the most momentum as the first mover exploiting a decade long competitive edge with its FlexRig designs. From an organic growth perspective, HP's leading market in 1,500hp AC-electric rigs and now in super-spec rigs has enabled the company to increase its total US market share by 500 basis points to 21% from the 2014 highs. This is more than any of its peers on an organic level, but when accounting for the acquisition of Seventy Seven Energy by Patterson-UTI Energy, it ranks a close second.

Figure 385: Top 4 land drillers combined market share



Source: Company reports, Deutsche Bank

Figure 386: Market share gains since 2014 peak activity



Source: Company reports, Deutsche Bank

Diminished earnings power in the US Land segment

Over the last ten years, the US Land segment has contributed 88% of the company's total segment EBITDA. Benefitting from the rapid expansion in US land drilling prompted by higher oil prices and the development of tight oil reserves, HP's US Land segment achieved a high water mark EBITDA of $1.48 billion in fiscal 2014. This corresponds to about $5.3 million per rig. EBITDA from this segment has since plummeted with the decline in oil prices and we model a bottom at about $377 million in fiscal 2017, or $2.4 million per rig.

We think the scarcity value in the US land drilling market has been eliminated over the next cycle. Drilling more with less has bifurcated the market and has created a challenging pricing environment. We believe it will be tough for HP to restore its daily margins to the $15,000 per day run rate and expect $10,000 per day to be at the high-end over the next few years. The company has gained 500 basis points of market share to 21% with ambitions for 25%. At that level and assuming upside to a daily margin of $10,000, HP's US Land business can rebuild its EBITDA power to about $0.89 billion in our view.

Figure 387: HP US Land segment EBITDA sensitivity to changes in rig count and daily margin

Daily margin	Rig working 100	125	150	175	200	225	250	275	300	325	350
$ 15,000	490	625	760	895	1,030	1,165	1,300	1,435	1,570	1,705	1,840
$ 14,000	454	580	706	832	958	1,084	1,210	1,336	1,462	1,588	1,714
$ 13,000	418	535	652	769	886	1,003	1,120	1,237	1,354	1,471	1,588
$ 12,000	382	490	598	706	814	922	1,030	1,138	1,246	1,354	1,462
$ 11,000	346	445	544	643	742	841	940	1,039	1,138	1,237	1,336
$ 10,000	310	400	490	580	670	760	850	940	1,030	1,120	1,210
$ 9,000	274	355	436	517	598	679	760	841	922	1,003	1,084
$ 8,000	238	310	382	454	526	598	670	742	814	886	958
$ 7,000	202	265	328	391	454	517	580	643	706	769	832
$ 6,000	166	220	274	328	382	436	490	544	598	652	706

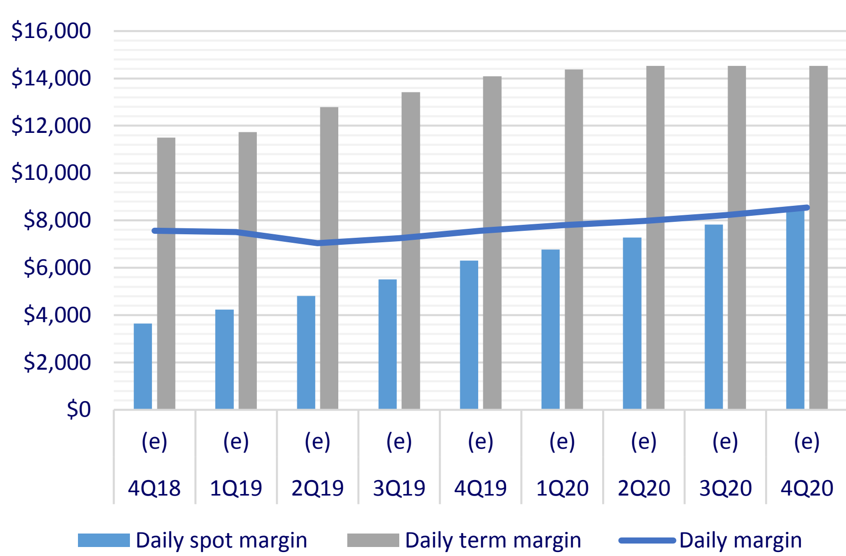
Source: Deutsche Bank

The dividend is manageable, but a threat depending on strategy

HP's dividend has polarized the stock. The roll-off of legacy priced contracts to spot market pricing created a lot of concern that the resulting plunge in average daily margins would prompt the company to cut its dividend. With daily spot margins less than $4,000 per day and with half of the contracted rigs on term commitments, the concern gained steam. The company has since disclosed its expected annual rig margin per day for its long-term contracts for fiscal 2018, 2019 and 2020 at $13,000, $14,500 and $15,500 respectively.

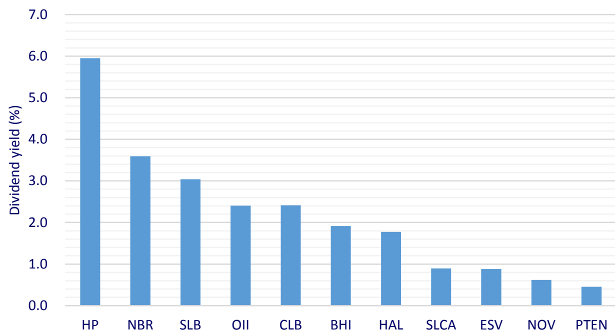
Assuming capex of $350-400 million in 2018 and $325 million in 2019, and no major cash outlays for M&A, the dividend is manageable in our view. But the margin is thin enough that the threat may linger. The company has been clear it will not issue debt to maintain the dividend.

Figure 388: US Land segment daily margin mix



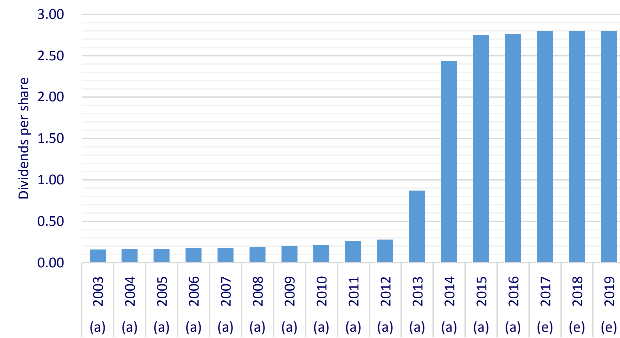
Source: Deutsche Bank

Figure 389: HP has the leading dividend yield



Source: Company reports, Deutsche Bank

Figure 390: Helmerich & Payne annual dividend



Source: Company reports, Deutsche Bank

Valuation and risks

We are initiating coverage of Helmerich & Payne with a $45 price target. This is 5.5x our estimate of the company's normalized EBITDA of $0.9 billion, which is in-line with the 5.5x five-year average multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 12x our fiscal 2018 EBITDA estimate of $0.45 billion, and 10x our 2019 EBITDA estimate of $0.55 billion. We expect valuations will continue to consolidate as markets reassess the earnings power of the industry and the company due to the unprecedented influence US oil production is having on global oil prices and drilling activity.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a dividend cut, and 4) a step up in cost inflation in the US Land segment.

Figure 391: The EV/EBITDA valuation band as blown out

Source: Factset

Figure 392: The 5yr EV/EBITDA leading up to 2014

Source: Factset

Company description

Helmerich & Payne (HP) is the largest land drilling company in the US where it has a fleet of 350 land rigs and 21% market share. The company has three reporting segments: US Land, International Land and Offshore. The US Land segment accounted for 73% of 2016 revenues and consists almost exclusively of HP's proprietary FlexRigs. International Land was 16% of 2016 revenues and consists of 38 land rigs in South America and the Middle East. Offshore was 10% of 2016 revenues and includes eight platform rigs in the Gulf of Mexico.

Figure 393: Company reporting segments

Helmerich & Payne

US Land
- Land drilling - 348 land rigs
  - Tubular runnning services
  - Directional drilling services (MOTIVE)
  - Rotary steerable systems (TerraVici)

International Land
- Land drilling - 38 land rigs
  - Argentina - 1
  - Colombia - 8
  - Ecuador - 6
  - Bahrain - 3
  - UAE - 2

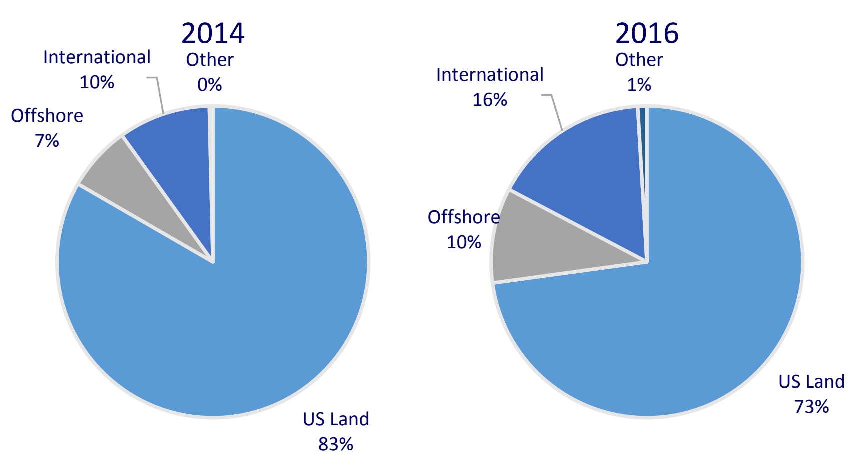
Offshore
- Fleet 8 platform rigs in the US Gulf of Mexico

Other
- Commercial real estate (Tulsa, OK)
- Terra Vici Drilling Solutions (rotary steerables)
- MOTIVE (bit guidance systems)

Source: Deutsche Bank

HP is also acquiring and developing service content for its rigs. In addition to providing tubular running services (TRS) on half of its rigs in the Permian, the company recently acquired MOTIVE, which has developed a bit guidance system for directional drilling applications. Through its subsidiary Terra Vici Drilling Solutions, HP has also been developing rotary steerable technology. The company intends to develop increasingly more service content in order to rebuild earnings power.

Figure 394: Revenues by reporting segment



Source: Company reports

Principal Sources and Uses of Cash Flow

Helmerich & Payne's core business is land drilling and its principal market is the US. For almost 20 years, the company has focused on the development of its proprietary FlexRig designs which offer enhanced mobility and faster rates of penetration (ROP). The company established a significant competitive edge with these rigs that it exploited for almost a decade until its peers began offering similar rig functionalities in response to strong customer demand.

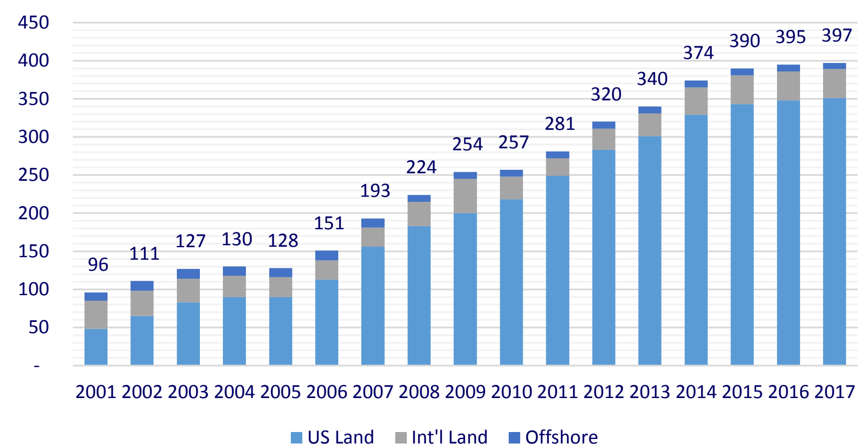
Figure 395: FlexRig newbuild program delivered 392 rigs since the FlexRig1

Global newbuild program	USA	Argentina	Colombia	Ecuador	Bahrain	UAE	Retired	Total
FlexRig1	0	0	0	0	0	0	6	6
FlexRig2	0	0	0	0	0	0	12	12
FlexRig3	218	11	2	0	0	2	0	233
FlexRig4	78	4	3	0	3	0	0	88
FlexRig5	52	0	1	0	0	0	0	53
Total newbuilds	**348**	**15**	**6**	**0**	**3**	**2**	**18**	**392**

Source: Company reports, as of fiscal 3Q17, Deutsche Bank

We estimate the company has spent close to $7 billion on the design and construction of over 390 FlexRigs since the original six FlexRig1s were delivered in the late 1990s. The company now has 348 FlexRigs in the US and 26 in international markets. Included in the US rig fleet are 326 of the preferred 1,500hp AC-electric rigs, of which 148 are super-spec rigs.

Figure 396: Organic fleet growth

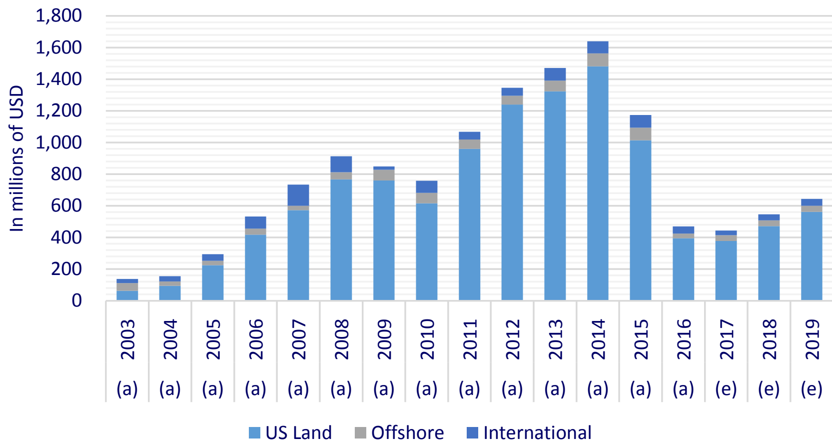


Source: Company reports, Deutsche Bank

The US Land segment has contributed 88% of the EBITDA over last ten years

Helmerich & Payne is one of the only principal players in the US land market that has been a high growth company. Over the ten years leading up to the collapse in oil prices in 2014, EBITDA from its US Land segment had increased ten-fold. Contributing to this growth was a three-fold increase in fleet size and a three-fold increase in US daily rig margins. While the company has invested in a relatively small international presence, the US land drilling business will likely continue as the principal source of cash flow.

Figure 397: Helmerich & Payne segment EBITDA

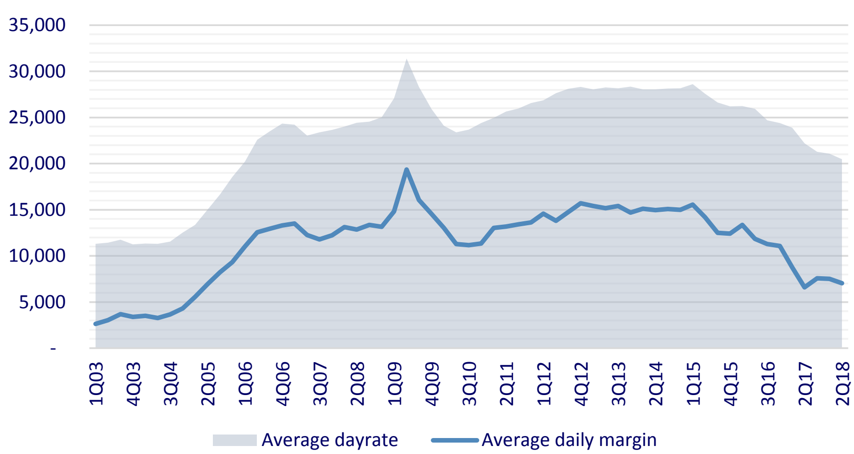


Source: Company reports, Deutsche Bank

Drilling more with less undermines rig pricing

HP realized leading edge pricing during the upswing of tight oil development with multi-year commitments that reached in some cases above $30 kpd. Scarcity value was high as rigs were stretched between development work, hold-by-production (HBP) operations and exploration. The surge in high-yield debt and equity issuances funded a proliferation of capital spending with a high urgency to secure high-specification rigs that could enable higher drilling efficiencies and lower well costs. One of the key outcomes was a 50% increase in the number of wells a high-specification rig could spud per year.

Figure 398: HP average daily revenues and margins in US Land



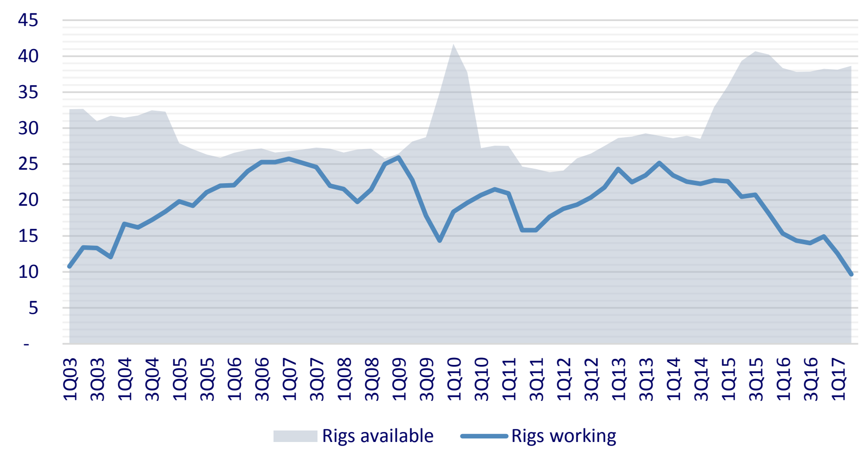
Source: Company reports, Deutsche Bank

Now with a higher cadence of more productive wells being drilled with less capital and fewer rigs, industry pricing has lost the scarcity value. We do not expect HP or the industry will be able to recover the same level of pricing power until oil markets rebalance.

Lackluster outlook for international land opportunities

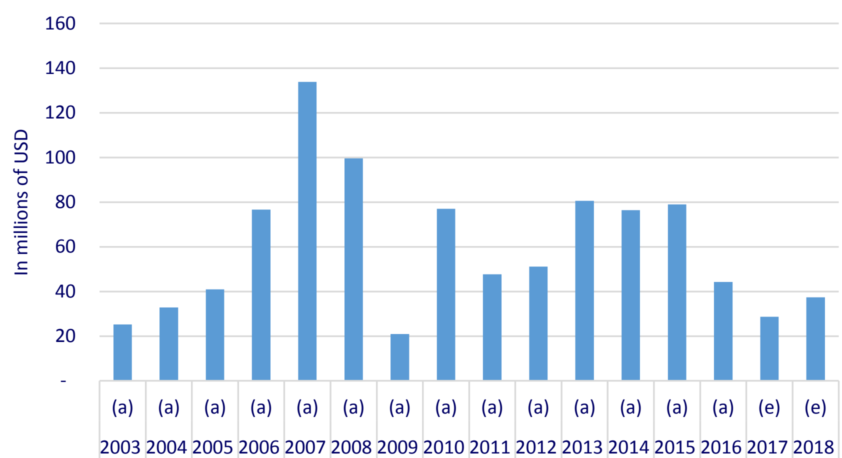
We do not expect the contribution from the International Land segment to change much for HP. Argentina is its primary source of international cash flow with 12 of its 19 rigs in the country contracted. We expect HP's International Land segment to contribute less than $40 million of EBITDA in 2018.

Figure 399: International rigs working vs available



Source: Company reports, Deutsche Bank

Figure 400: International Land EBITDA



Source: Company reports, Deutsche Bank

HP does not intend to fund any more newbuilds in this environment

The company has had a long track record in investing in newbuilds. About 80% of the company's cumulative capex over the past ten years has been directed to its FlexRig program. Due to the uncertain environment, the company is opting out of the newbuild market and is focusing on upgrades of its remaining 122 candidate rigs at approximately $2-3 million apiece.

Figure 401: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
US Land	1,441	1,412	2,101	2,678	2,785	3,100	2,320	1,024	1,397	1,652	1,790
Offshore	205	203	201	189	222	251	241	139	135	133	135
International	237	254	227	270	367	356	368	230	191	199	231
Other	11	13	15	14	13	13	14	13	15	17	17
Total revenues	1,894	1,882	2,544	3,152	3,387	3,720	2,943	1,405	1,738	2,001	2,173
Segment EBITDA:											
US Land	761	616	959	1,240	1,324	1,482	1,015	396	377	473	566
Offshore	67	66	60	55	67	82	79	29	37	37	38
International	21	77	48	51	81	76	79	44	29	37	45
Corp, other	(36)	(50)	(59)	(68)	(78)	(81)	(85)	(88)	(93)	(98)	(97)
EBITDA	813	708	1,008	1,278	1,393	1,559	1,088	382	351	450	551
D&A	236	267	313	388	456	507	570	560	544	551	545
EBIT	577	441	695	890	937	1,052	518	(179)	(193)	(101)	7
Interest (expense)	(13)	(17)	(17)	(9)	(6)	(5)	(15)	(23)	(24)	(25)	(25)
Interest income	5	2	2	1	2	2	6	3	5	5	3
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	1	1	(1)	0	(0)	(1)	(1)	(0)	(1)	(4)	(4)
PBT	569	427	679	883	933	1,048	508	(199)	(213)	(125)	(19)
Income tax (expense)	(229)	(153)	(245)	(323)	(323)	(370)	(181)	89	67	40	6
Non-controlling interest	10	0	0	0	0	0	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	350	274	434	560	610	679	327	(110)	(146)	(86)	(13)
Discontinued ops	0	(102)	(0)	7	15	(0)	(0)	(4)	0	0	0
Unusual after-tax	4	(16)	4	13	111	30	96	57	16	0	0
Net income (GAAP)	354	157	437	581	736	709	422	(57)	(129)	(86)	(13)
Operating EPS	**3.28**	**2.56**	**4.00**	**5.17**	**5.66**	**6.20**	**2.98**	**(1.03)**	**(1.34)**	**(0.79)**	**(0.12)**
GAAP EPS	3.32	1.46	4.03	5.36	6.83	6.48	3.86	(0.54)	(1.19)	(0.79)	(0.12)
DPS	0.20	0.21	0.26	0.28	0.87	2.44	2.75	2.76	2.80	2.80	2.80
Diluted shares	107	107	109	108	108	109	108	108	108	109	109
EBITDA margin	42.9%	37.6%	39.6%	40.5%	41.1%	41.9%	37.0%	27.2%	20.2%	22.5%	25.4%
EBIT margin	30.5%	23.5%	27.3%	28.2%	27.7%	28.3%	17.6%	-12.7%	-11.1%	-5.0%	0.3%
Tax rate	40.3%	35.8%	36.1%	36.6%	34.6%	35.3%	35.7%	44.7%	31.6%	31.6%	31.6%
US Land Drilling:											
Rigs working	132	151	202	236	243	276	208	101	156	197	209
Rigs available	194	207	236	265	295	321	337	340	348	350	350
Utilization	68%	73%	86%	89%	82%	86%	62%	30%	45%	56%	60%
Daily revenue	28,194	23,909	25,809	27,737	28,197	28,096	27,528	25,448	22,051	20,585	21,029
Daily margin	16,185	11,621	13,320	14,715	15,169	15,038	14,045	12,050	7,502	7,333	8,133
International Land Drilling:											
Rigs working	20	20	18	20	24	23	20	15	12	15	17
Rigs available	30	34	25	26	29	30	39	38	38	38	38
Utilization	68%	60%	70%	77%	83%	76%	52%	39%	32%	38%	44%
Daily revenue	29,650	33,116	31,633	32,998	37,246	37,117	44,183	39,044	40,415	36,172	36,172
Daily margin	3,657	11,128	8,217	7,474	9,657	9,839	10,645	10,625	7,786	8,472	8,472

Source: Deutsche Bank

Figure 402: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Net income	350	274	434	560	610	679	327	(110)	(146)	(87)	(16)	19
Depreciation	236	267	313	388	456	507	570	560	544	551	545	535
Deferred tax	158	106	188	197	30	27	132	60	(28)	0	0	0
Chg in receivables	217	(224)	(3)	(160)	(5)	(84)	256	73	(74)	(19)	(28)	(12)
Chg in inventories	(12)	(4)	(11)	(22)	(12)	(17)	(22)	2	(13)	(4)	(4)	(4)
Chg in payables	(29)	17	17	55	(52)	(21)	(71)	(11)	43	4	4	4
Other	(24)	26	40	(17)	(28)	28	229	179	21	8	12	5
Cash from operations	897	462	978	1,000	997	1,119	1,419	754	347	452	512	548
Capital expenditures	(881)	(330)	(694)	(1,098)	(809)	(953)	(1,133)	(257)	(400)	(368)	(324)	(311)
Free cash flow	17	133	283	(97)	188	166	285	496	(54)	84	188	236
Acquisitions	(0)	0	(4)	0	0	0	0	0	(70)	0	0	0
Asset sales	9	8	27	40	28	31	23	22	18	0	0	0
Dividends paid	(21)	(22)	(27)	(30)	(93)	(264)	(298)	(300)	(305)	(304)	(304)	(304)
ESPP | options	1	(0)	15	3	13	23	3	1	10	0	0	0
Equity issuance, net	0	0	0	(78)	0	0	(60)	0	0	0	0	0
Debt issuance, net	23	(165)	(10)	(115)	(40)	(115)	452	(41)	0	0	0	0
Other	4	(44)	16	9	255	73	(1)	8	(2)	0	0	0
Chg in cash	32	(91)	301	(268)	352	(87)	403	186	(403)	(220)	(116)	(68)

Source: Deutsche Bank

Figure 403: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Cash and equivalents	154	63	364	96	448	361	764	950	547	327	211	143
Accounts receivable	247	458	461	620	621	705	449	375	452	471	500	511
Inventories	45	43	54	79	89	106	129	124	140	144	148	152
Other current assets	77	89	77	100	100	105	97	123	61	63	67	69
Total current assets	523	653	956	895	1,258	1,277	1,439	1,573	1,200	1,006	926	876
Net PP&E	3,266	3,275	3,677	4,352	4,676	5,189	5,567	5,145	5,025	4,842	4,622	4,398
Goodwill	0	0	0	0	0	0	0	0	52	52	52	52
Other assets	895	990	1,327	1,370	1,589	1,533	1,585	1,687	1,351	1,160	1,085	1,037
Total assets	4,161	4,265	5,004	5,721	6,265	6,722	7,152	6,832	6,428	6,054	5,759	5,486
Accounts payable	70	81	104	159	144	182	111	95	139	143	147	151
Current debt	105	0	115	40	115	40	39	0	0	0	0	0
Other current liabilities	127	152	198	182	193	285	201	235	204	213	225	231
Total current liabilities	302	233	417	381	452	508	351	330	343	355	372	381
Long-term debt	420	360	235	195	80	40	492	492	493	493	493	493
Other LT liabilities	1,058	1,098	1,499	1,691	1,741	1,791	1,762	1,779	1,784	1,802	1,826	1,838
Shareholders' equity	2,683	2,807	3,270	3,835	4,444	4,891	4,897	4,561	4,151	3,760	3,440	3,155
Total liabilities and equity	4,161	4,265	5,004	5,721	6,265	6,722	7,152	6,832	6,428	6,054	5,759	5,486
Total debt	525	360	350	235	195	80	532	492	493	493	493	493
Net debt	371	297	(14)	139	(253)	(281)	(232)	(458)	(54)	165	281	349
Debt/capital	16%	11%	10%	6%	4%	2%	10%	10%	11%	12%	13%	14%
Debt/equity	20%	13%	11%	6%	4%	2%	11%	11%	12%	13%	14%	16%
Debt turns	**0.6**	**0.5**	**0.3**	**0.2**	**0.1**	**0.1**	**0.5**	**1.3**	**1.4**	**1.1**	**0.9**	**0.8**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Nabors Industries

Reuters	Bloomberg
NBR.N	NBR US

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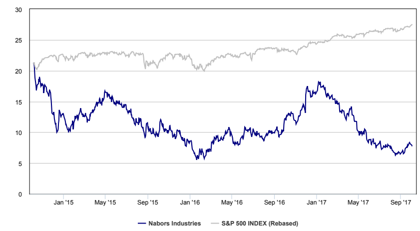
Price at 5 Oct 2017 (USD)	7.99
Price target	9.00
52-week range	18.19 - 6.27

Price/price relative



Performance (%)	1m	3m	12m
Absolute	18.2	-9.4	-34.6
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	2,226.3
Shares outstanding (m)	278.6
Free float (%)	100
Volume (5 Oct 2017)	1,505,147
Option volume (und. shrs., 1M avg.)	324,263

Source: Deutsche Bank

A focus on technology and service content

Initiating coverage with a Hold rating and a $9 price target

NBR is looking to restore its earnings power by driving its integration and automation efforts, added service content, and cost reductions. The company is also focusing on increasing revenues from services closely aligned to its drilling rigs, e.g. directional drilling, automated tubular handling and casing. We believe NBR has good line-of-sight to restoring EBITDA to $1.4 – 1.5 billion in the 2020 timeframe, but we believe the company will fall short of its net debt reduction to $2.2 billion by 2020.

NBR intends to extract more value from its existing rigs to restore EBITDA

NBR's core strategy is to extract more value from its large installed base of land rigs by increasing the penetration and scale of Nabors Drilling Solutions (NDS) on its rigs and by displacing third-party services. Ultimately, NBR is looking to restore its earnings power without having to depend on the industry returning to peak drilling activity. NBR sees $200-250 million of EBITDA opportunity with the largest piece of the daily margin upside in wellbore placement services.

Virtually every NBR rig in the US as at least one NDS service on it now

About 60% of its US rigs have two services, and more than half of its international rigs as at least one NDS service. The company just received qualification for wellbore placement in Saudi Arabia, which NBR believes will be the big driver of NDS penetration outside of the US lower-48. NDS hit an annual EBITDA run rate of $30m in 2Q17 and is targeting a $50m run rate by 4Q17.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.29	-0.49A	-0.22
2Q EPS	-0.26	-0.38A	-0.17
3Q EPS	-0.36	-0.33	-0.10
4Q EPS	-0.30	-0.27	-0.03
FY EPS (USD)	-1.21	-1.47	-0.51
OLD FY EPS (USD)	-1.22	-1.37	-0.10
% Change	-1.4%	7.6%	409.4%
P/E (x)	–	–	–
DPS (USD)	0.24	0.24	0.24
Dividend Yield (%)	2.3	3.0	3.0
Revenue (USDm)	2,227.8	2,565.7	3,264.9

Source: Deutsche Bank estimates, company data

Valuation

Our $9 price target is 5.0x our estimate of the company's normalized EBITDA of $1.3 billion, which is in-line with the 5.0x five-year average multiple leading up to the 2014 collapse in oil prices. Valuations have consolidated due to the high leverage in our view as markets reassess the earnings power, but also the probability that NBR can reduce net debt meaningfully using cash from operations. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an equity raise to reduce debt, and 4) a derailing of its efforts to increase the scale and penetration of its NDS services that would lead to a negative revision in earnings.

Key investment themes

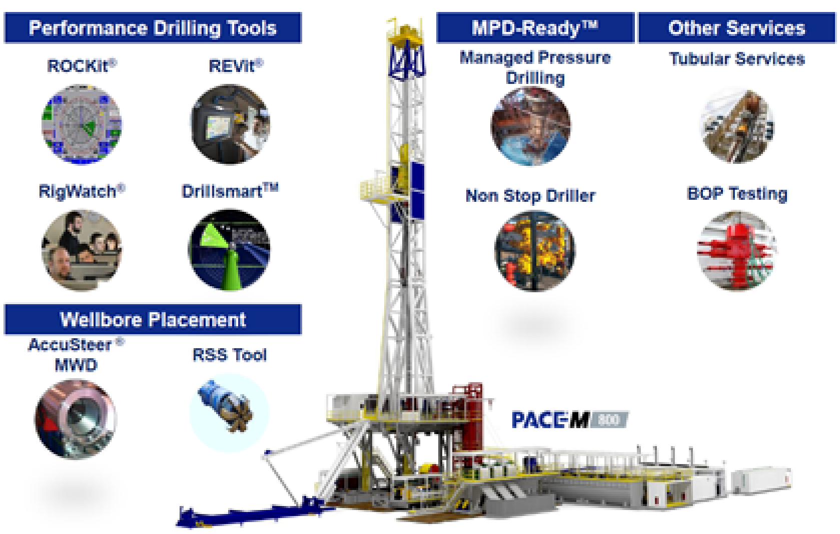
Evolving to reestablish the company in the value chain

Improved drilling efficiencies and enhanced completion designs have enabled US producers to drill a higher cadence of more productive wells using fewer rigs. This has undermined the earnings power of the land drilling industry and has forced its key players to devise strategies that will reestablish them in the value chain. For NBR, the core focus is not market share, it is on technology initiatives and service content to enhance its global rig margins.

NBR intends to extract more value from its existing installed base

NBR's core strategy as it navigates the transition in the land drilling industry is to extract more value from its large installed base of land rigs by increasing the penetration and scale of Nabors Drilling Solutions (NDS) on its rigs and by displacing third-party services. Ultimately, NBR is looking to restore its earnings power without having to depend on the industry returning to peak drilling activity. Initially the company plans to extract higher margins from its global rig fleet by pushing price and controlling costs, which includes making crews more efficient by using its NDS applications and automation. Beyond that, NBR intends to drive penetration of its NDS services across the US as well as a strong focus on its international markets, which are now 45% of the company's active rig count. In the end, full drilling automation is NBR's objective.

Figure 404: Nabors Drilling Solutions (NDS) is core to extracting more value



Source: Nabors Industries

NDS penetration is key variable for restoring earnings power

NBR sees about $200-250 million of EBITDA opportunity if it can extract more value from its existing rig base. The largest piece of the daily margin upside is wellbore placement services, which NBR believes is half of the total daily margin opportunity. This consists of the company's AccuSteer MWD and its RSS tool. Managed pressure drilling (MPD) is about 25% of the opportunity with the remainder in performance drilling tools and other services.

Virtually every NBR rig in the US has at least one NDS service on it, and about 60% have two services. More than half of NBR's international rig fleet as at least one NDS service. The company just received qualification for wellbore placement in Saudi Arabia, which NBR believes will be the big driver of NDS penetration outside of the US lower-48. In terms of directional drilling in the US, NBR has about 20% penetration, which means it can execute jobs on 27 rigs, with the goal of 44 by the end of the year.

NDS hit an annual EBITDA run rate of $30m in 2Q17 and is targeting a $50m run rate by 4Q17. We believe NBR will use acquisitions to reach its goal, a few of which have already been done (Tesco Corporation and Robotics Drilling Systems AS). Ultimately the target is $200-250 million by 2020.

Figure 405: Nabors Drilling Solutions (NDS) EBITDA opportunity

# of global rigs with services	Number of $1,000 margin services per rig (1)		
	3	5	7
170-200	$150-175m	$250-290m	$350-410m
140-170	$125-150m	$200-250m	$285-350m
110-140	$100-125m	$160-200m	$225-285m

(1) Assumes $1,000 of EBITDA margin/service/rig and 80% utilization

Source: Company reports, Deutsche Bank

Over the last eight years, NBR's global weighted daily rig margin has been in a range of $10,000 – 15,000 per day (figure 408). Assuming the company can achieve its daily margin enhancement goals, the company can see a global weighted margin of $14,500 and an earnings power of $1.6 billion by 2020 at a rig count that is 80% of its highs in 2014. We believe the key headwind will be pricing and execution. There are too many competitors that are market share driven and that are being aggressive on pricing. While the $1.6 billion is achievable in a robust market in our view, we believe industry conditions will confine the upside closer $1.4 – 1.5 billion.

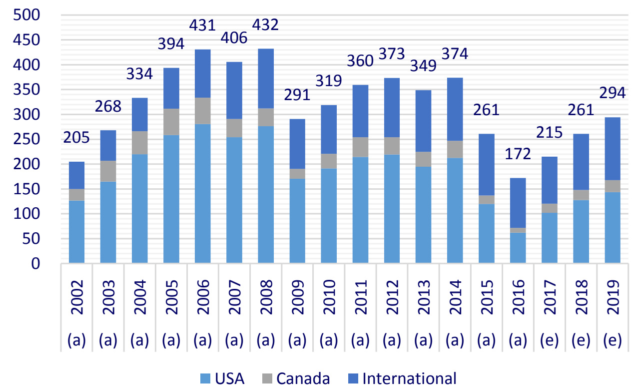
Figure 406: NBR EBITDA sensitivity to global rig count and daily margins

Weighted global margin ($'000)	Nabors global rig years		
	270	295	320
$16.0	$1,620	$1,760	$1,900
$14.5	$1,470	$1,600	$1,730
$13.0	$1,320	$1,440	$1,560

Note: EBITDA is in million of USD

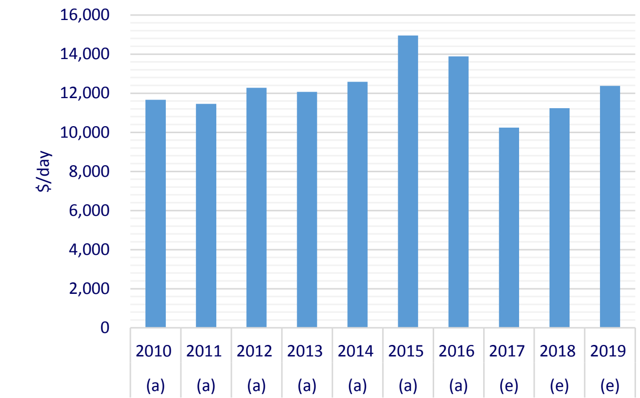
Source: Company reports, Deutsche Bank

Figure 407: NBR global rig years



Source: Company reports, Deutsche Bank

Figure 408: NBR global weighted daily margins



Source: Company reports, Deutsche Bank

NBR is placing another 23 super-spec rigs into service through 1Q18

Since 2005, NBR has been retiring its legacy rigs and building out its proprietary PACE (programmable AC-electric) rig fleet. The company now has 163 PACE rigs in the US, 77 of which are super-spec rigs that are earnings premiums as high as $2,000 per day over 1,500hp AC-electric rigs. NBR is placing another 23 super-spec rigs into service through 1Q18, seven of which are $18-19 million newbuilds and 16 that are $2-4 million upgrades. But NBR does not intend to fund any more newbuilds for the US, and there are limited number of suitable upgrade candidates left in its fleet.

Figure 409: Nabors US Lower-48 rig fleet

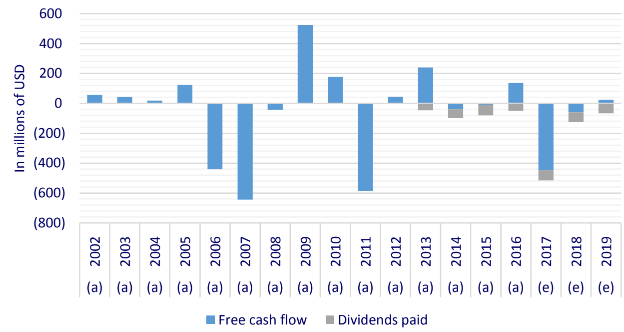
US Lower 48 rig fleet	Walking	Skidding	Total pad	Not pad	Total rigs	% pad
PACE-X	46	0	46	0	46	100%
PACE-M800	6	0	6	0	6	100%
PACE-B	28	0	28	1	29	97%
PACE-S	9	2	11	0	11	100%
PACE-F	4	6	10	8	18	56%
PACE M550	30	8	38	18	56	68%
Other AC rigs	12	4	16	1	17	94%
Total AC rigs	**135**	**20**	**155**	**28**	**183**	**85%**
SCR rigs	3	5	8	16	24	33%
Total US Lower 48 rigs	**138**	**25**	**163**	**44**	**207**	**79%**

Source: Company reports

NBR is focused on reducing leverage

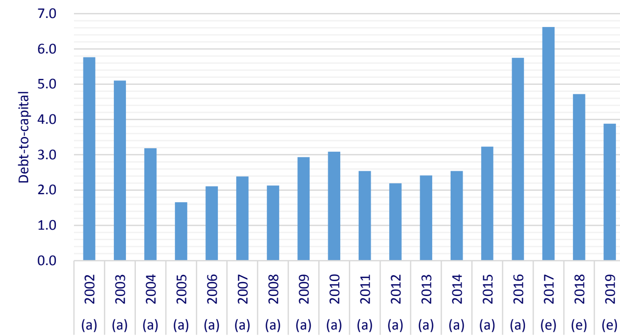
A primary overhang for NBR has been its leverage. The company closed 2Q17 with debt turns of 7.0x and total net debt of $3.5 billion. The company has committed to reducing net debt to $2.2 billion by 2020, however this requires a robust recovery to realize this degree of pay down. While we believe there is line of sight to NBR's EBITDA ambitions, we do not have line of sight on its $1.3 billion net debt reduction plans. We estimate the company will be free cash flow negative in 2017 by about $0.4 billion and by about $0.1 billion in 2018. We expect a positive pivot in 2019, but not enough to get it to a net debt of $2.2 billion in 2020. We believe there will have to be an alternative strategy to achieving this goal.

Figure 410: NBR free cash flow and dividends paid



Source: Company reports, Deutsche Bank

Figure 411: NBR debt turns

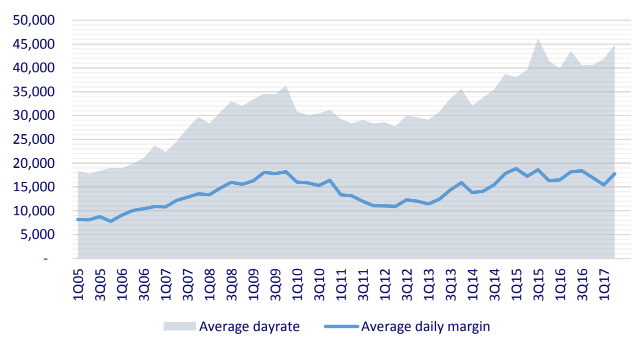


Source: Company reports, Deutsche Bank

International execution has some tailwinds

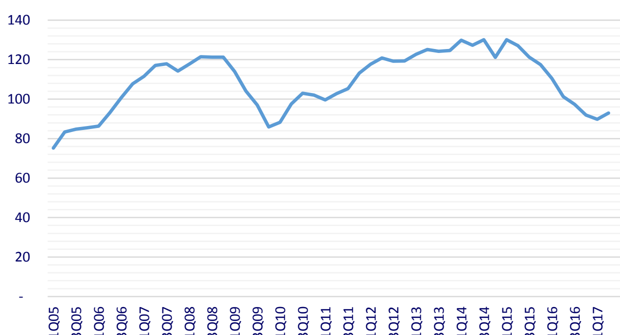
International rig margins have gained some traction and NBR has at last seen a pivot in its international rig count. An interesting win for NBR is its 50/50 joint venture with Saudi Aramco, SANAD (Saudi Aramco Nabors Drilling), which commences in 2H17. NBR and Saudi Aramco have each committed $20 million in cash and will commit five land rigs each to the JV. Initially the impact will be small for NBR, but in two years the JV will add five rigs per year over a period of ten years from a base of NBR's 38 rigs in 2Q17.

Figure 412: International daily margins (USD)



Source: Company reports, Deutsche Bank

Figure 413: International rig count



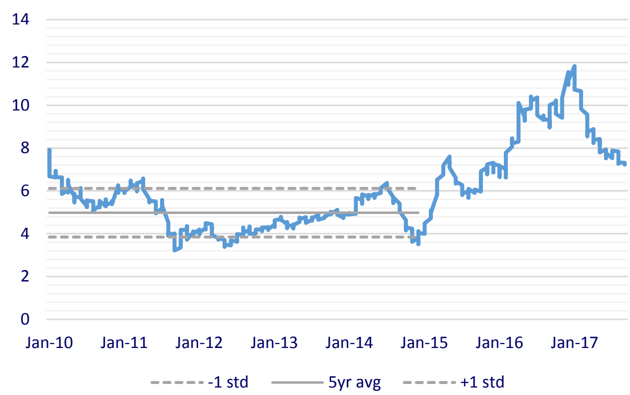
Source: Company reports, Deutsche Bank

Valuation and risks

We are initiating coverage of Nabors Industries with a $9 price target. This is 5.0x our estimate of the company's normalized EBITDA of $1.3 billion, which is in-line with the 5.0x five-year average multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 7.6x our fiscal 2018 EBITDA estimate of $0.82 billion, and 6.0x our 2019 EBITDA estimate of $1.04 billion. Valuations have consolidated due to the high leverage in our view as markets reassess the earnings power, but also the probability that NBR can reduce net debt meaningfully using cash from operations.

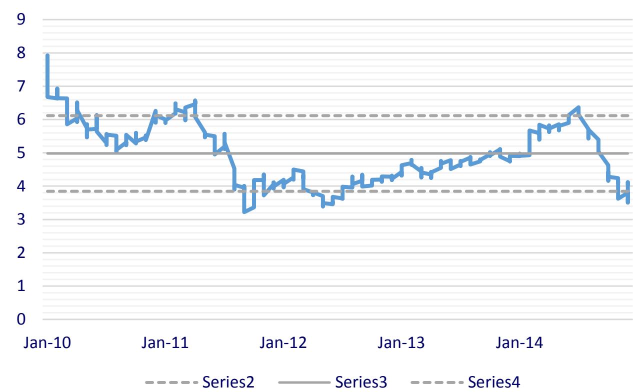
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an equity raise to reduce debt, and 4) a derailing of its efforts to increase the scale and penetration of its NDS services that would lead to a negative revision in earnings.

Figure 414: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 415: The 5yr EV/EBITDA leading up to 2014



Source: Factset

Company description

Nabors Industries (NBR) is the largest land drilling company with over 400 land rigs. Its largest presence is in the US, where it has 222 land rigs, making it the third largest with 12% market share. The company's international land fleet includes 137 rigs in 20 countries with a particular leverage to Saudi Arabia and Latin America. In Canada, NBR has 47 land rigs and 8% market share. The company is also a leading provider of platform rigs with 17 in the Gulf of Mexico and 18 platform rigs plus six jackups in international markets.

Figure 416: Company reporting segments

Nabors Industries

US Drilling
- US Lower 48 - 206 land rigs
- US Offshore - 17 platform rigs
- Alaska - 16 land rigs

International Drilling
- Land drilling - 137 land rigs
- Offshore drilling
  - 9 platform drilling rigs
  - 9 platform workover rigs
  - 6 jackups rigs

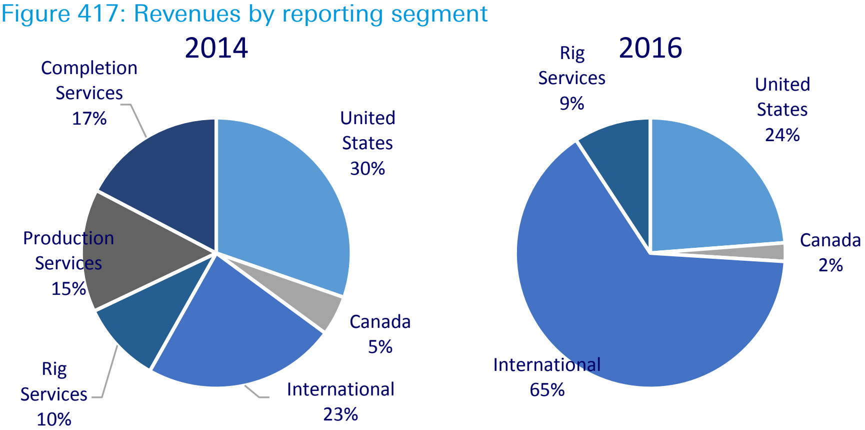
Canada Drilling
- Canada fleet of 47 land rigs

Rig Services
- Nabors Drilling Solutions (NDS)
  - Rigtelligent™ integrated operating system
  - Accu directional tools
  - Rotary steerable systems
  - iRacker™ autonomous tubular handling
  - RIGWATCH® rig performance monitoring
  - ROCKIT® directional drilling systems
  - REVit® control systems
  - DRILLSMART® rig performance monitoring
  - Recipe to Drill™ work flow
  - Tubular running services equiment
- Ryan Directional Services - directional drilling
- Canrig Drilling Technology
  - Top drives, catwalks, drawworks, wrenches

Source: Deutsche Bank

NBR's Rig Services segment includes its Canrig, Ryan Directional Services and Nabors Drilling Solutions (NDS) subsidiaries. Canrig manufactures and sells drilling equipment, mainly for internal use. Ryan provides directional drilling services, and NDS offers a broad spectrum of drilling technologies and applications that enhance rig performance and well placement. In 2015, NBR sold its completion and production services businesses to C&J Energy (CJ).

Figure 417: Revenues by reporting segment

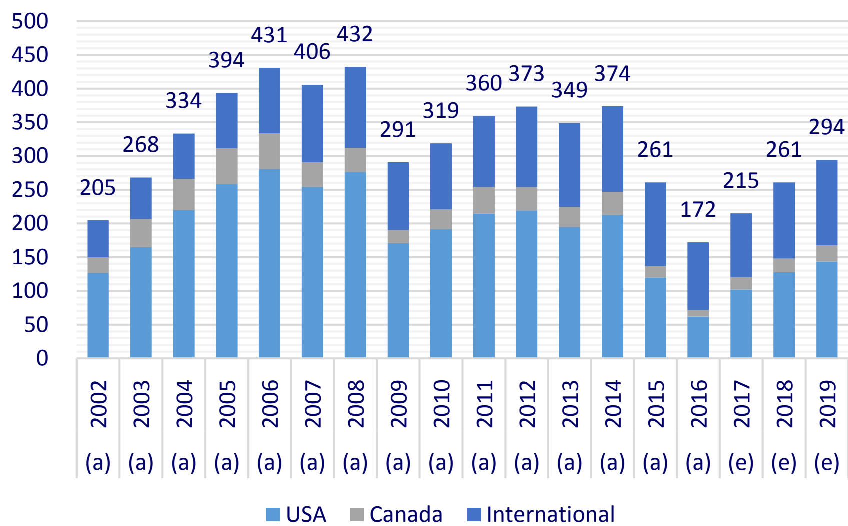


Source: Company reports

Principal Sources and Uses of Cash Flow

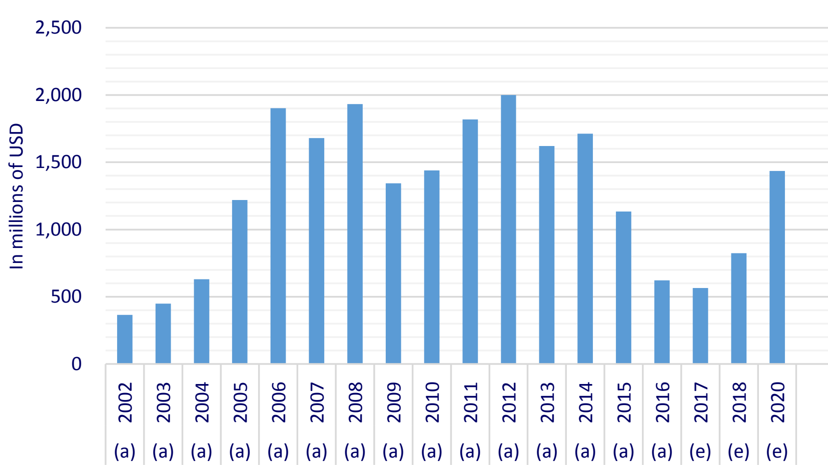
The US and international land markets are the principal sources of cash flow for NBR. In 2015, NBR sold its Completions and Production Services business to C&J Energy, which had accounted for almost one-third of its revenues, and about 16% of its EBITDA during the industry peak in 2014. NBR initiated a dividend in 2013, but through 2016, aggregate dividend payments only consumed about 5% of cash from operations. NBR does not intend to fund any more newbuilds as long as rates remain depressed, and the company has a limited inventory of suitable rigs to upgrade to super-spec capabilities. As such, capex is down 71% to $0.6 billion in 2017 from the peaking spending in 2011. NBR intends to reduce its net debt to $2.2 billion from

Figure 418: Global active rig count



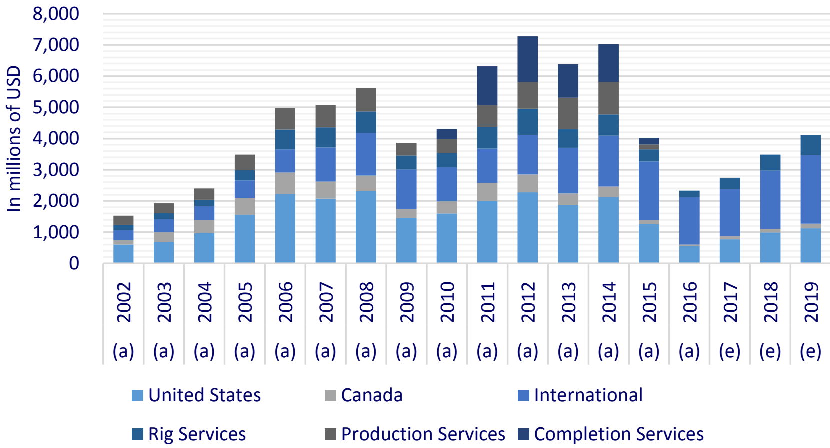
Source: Company reports, Deutsche Bank

Figure 419: Consolidated EBITDA



Source: Company reports, Deutsche Bank

Figure 420: Revenue contribution



Source: Company reports, Deutsche Bank

Figure 421: NBR global land fleet

		< 1,499 HP		1,500 HP		> 1,500 HP		Total			
Global Land Fleet	**Mech**	**SCR**	**AC**	**SCR**	**AC**	**SCR**	**AC**	**Mech**	**SCR**	**AC**	**Total**
US Lower 48	0	10	73	8	108	6	1	0	24	182	206
Alaska	1	4	5	0	1	5	0	1	9	6	16
Canada	19	12	11	2	1	1	1	19	15	13	47
Total North America	20	26	89	10	110	12	2	20	48	201	269
Saudi Arabia	1	0	0	11	2	25	4	1	36	6	43
Argentina	13	2	0	0	6	1	1	13	3	7	23
Colombia	0	0	0	3	8	3	0	0	6	8	14
Algeria	0	0	0	2	4	3	1	0	5	5	10
Russia	1	0	1	2	0	2	1	1	4	2	7
Ecuador	4	0	0	0	0	1	1	4	1	1	6
Mexico	0	1	0	1	0	4	0	0	6	0	6
Venezuela	0	1	0	0	4	0	0	0	1	4	5
Kazakhstan	1	0	0	0	0	4	0	1	4	0	5
Iraq	0	0	0	3	1	0	0	0	3	1	4
Other	0	4	0	0	0	5	5	0	9	5	14
International	20	8	1	22	25	48	13	20	78	39	137
Total global land fleet	40	34	90	32	135	60	15	40	126	240	406

Source: Company reports

Figure 422: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
United States	1,444	1,598	1,999	2,277	1,876	2,130	1,257	554	771	994	1,133
Canada	297	389	575	573	362	335	137	51	99	129	164
International	1,265	1,094	1,104	1,265	1,464	1,623	1,868	1,509	1,517	1,872	2,200
Rig Services	448	457	695	840	595	687	391	216	363	511	641
Production Services	412	445	701	858	1,009	1,034	159	0	0	0	0
Completion Services	0	321	1,237	1,463	1,075	1,218	208	0	0	0	0
Eliminations	(152)	(79)	(187)	(372)	(189)	(260)	(150)	(102)	(184)	(240)	(284)
Total revenues	3,715	4,225	6,125	6,902	6,192	6,768	3,871	2,228	2,566	3,265	3,854
Segment EBIT:											
United States	388	335	443	528	276	340	87	(198)	(208)	(117)	(60)
Canada	(7)	23	95	97	61	52	(7)	(37)	4	37	54
International	366	255	124	91	178	243	314	165	128	322	524
Rig Services	34	43	55	79	4	48	(13)	(48)	(2)	43	69
Production Services	29	32	75	104	102	93	(3)	0	0	0	0
Completion Services	0	67	229	189	52	(15)	(55)	0	0	0	0
Eliminations, other	(146)	(104)	(146)	(142)	(146)	(194)	(160)	(131)	(178)	(247)	(315)
Total EBIT	664	650	874	945	527	568	163	(249)	(255)	38	271
Interest (expense)	(265)	(273)	(256)	(252)	(223)	(178)	(182)	(185)	(217)	(193)	(174)
Interest income	26	3	12	0	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	0	(81)	(36)	0	0	0
Other income	(13)	2	(6)	9	4	(2)	(8)	(9)	(2)	0	0
PBT	412	382	624	702	307	388	(108)	(480)	(475)	(155)	97
Income tax (expense)	(42)	(53)	(186)	(196)	(56)	(56)	18	142	64	21	(7)
Non-controlling interest	0	(1)	(1)	(1)	(7)	(1)	(1)	(0)	(7)	(8)	(8)
Preferred dividends	0	(1)	(3)	(3)	(3)	(2)	0	0	0	0	0
Net income (operating)	369	327	435	503	241	329	(90)	(338)	(418)	(142)	82
Discontinued ops	0	(6)	(79)	(282)	(17)	0	(43)	(18)	(16)	0	0
Unusual after-tax	(455)	(226)	(111)	(57)	(85)	(1,045)	(240)	(673)	(15)	0	0
Net income (GAAP)	(86)	95	244	164	139	(716)	(373)	(1,029)	(449)	(142)	82
Conv int | share comp											
Operating EPS	**1.30**	**1.13**	**1.49**	**1.72**	**0.81**	**1.12**	**(0.30)**	**(1.21)**	**(1.47)**	**(0.51)**	**0.30**
GAAP EPS	(0.30)	0.33	0.83	0.56	0.47	(2.43)	(1.29)	(3.71)	(1.58)	(0.51)	0.30
DPS	0.00	0.00	0.00	0.00	0.16	0.20	0.24	0.24	0.24	0.24	0.24
Diluted shares	284	290	292	292	296	295	283	276	279	279	279
Consolidated EBITDA	1,343	1,440	1,819	2,000	1,622	1,713	1,134	622	565	830	1,049
EBITDA margin	36.2%	34.1%	29.7%	29.0%	26.2%	25.3%	29.3%	27.9%	22.0%	25.4%	27.2%
EBIT margin	17.9%	15.4%	14.3%	13.7%	8.5%	8.4%	4.2%	-11.2%	-9.9%	1.2%	7.0%
Tax rate	10.3%	13.9%	29.7%	27.9%	18.3%	14.3%	16.5%	29.7%	13.4%	13.4%	7.3%
Rigs working:											
US Lower-48	150	174	200	201	177	196	105	53	96	123	139
US Offshore	11	9	10	13	13	10	7	5	3	3	3
Alaska	10	7	5	6	5	6	8	4	3	3	3
Canada	20	30	40	35	30	34	17	10	18	23	27
International	100	98	105	119	124	127	124	100	94	113	127
Segment EBIT margins:											
United States	26.9%	21.0%	22.1%	23.2%	14.7%	16.0%	6.9%	-35.7%	-26.9%	-11.7%	-5.3%
Canada	-2.3%	5.8%	16.5%	16.9%	16.9%	15.7%	-5.1%	-71.5%	4.1%	28.7%	32.8%
International	28.9%	23.3%	11.2%	7.2%	12.1%	15.0%	16.8%	10.9%	8.4%	17.2%	23.8%
Rig Services	7.6%	9.5%	7.9%	9.4%	0.7%	7.0%	-3.2%	-22.5%	-0.6%	8.4%	10.8%

Source: Deutsche Bank

Figure 423: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	369	327	435	503	241	329	(90)	(338)	(418)	(147)	76
Depreciation	679	790	945	1,056	1,095	1,145	970	872	820	791	778
Deferred tax	(219)	56	(35)	(145)	(103)	(240)	(203)	(207)	(136)	(46)	14
Chg in receivables	451	(250)	(459)	201	(45)	(127)	529	250	(130)	(60)	(66)
Chg in inventories	53	(15)	(115)	14	39	(65)	24	41	(8)	(7)	(10)
Chg in payables	(146)	70	518	(223)	114	268	(566)	(180)	96	102	31
Other	430	129	169	158	78	472	193	94	(97)	(77)	(34)
Cash from operations	1,617	1,107	1,456	1,563	1,418	1,782	857	532	128	557	789
Capital expenditures	(1,093)	(930)	(2,043)	(1,519)	(1,178)	(1,821)	(867)	(395)	(576)	(616)	(765)
Free cash flow	524	177	(586)	44	240	(39)	(11)	136	(448)	(59)	24
Acquisitions	0	(734)	(112)	0	(117)	(73)	(80)	(22)	0	0	0
Asset sales	31	31	324	309	321	157	68	35	19	0	0
Dividends paid	0	0	0	0	(47)	(59)	(69)	(51)	(68)	(67)	(67)
ESPP | options	11	1	0	0	0	0	0	0	0	0	0
Equity issuance, net	(8)	2	9	(6)	5	(220)	(98)	(1)	8	0	0
Debt issuance, net	25	298	153	(246)	(690)	216	(677)	(70)	302	150	150
Other	(76)	(65)	(49)	137	17	47	606	(6)	(33)	0	0
Chg in cash	507	(290)	(262)	239	(271)	29	(262)	21	(219)	24	107
FCF per share	1.84	0.61	(2.00)	0.15	0.81	(0.13)	(0.04)	0.49	(1.61)	(0.21)	0.09
Capex / revenue	0.29	0.22	0.33	0.22	0.19	0.27	0.22	0.18	0.22	0.19	0.20
Capex / depreciation	1.61	1.18	2.16	1.44	1.08	1.59	0.89	0.45	0.70	0.78	0.98

Source: Deutsche Bank

Figure 424: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	1,091	801	539	778	507	536	275	295	76	99	207
Accounts receivable	724	1,117	1,577	1,383	1,400	1,518	785	508	624	684	750
Inventories	101	159	273	251	210	230	154	104	112	119	128
Other current assets	261	536	699	721	637	458	263	249	278	358	392
Total current assets	2,177	2,613	3,088	3,133	2,754	2,742	1,476	1,156	1,090	1,260	1,477
Net PP&E	7,646	7,815	8,630	8,712	8,598	8,599	7,028	6,268	5,994	5,819	5,807
Goodwill	164	494	501	472	513	174	167	167	167	167	167
Other assets	2,834	3,337	3,781	3,472	3,049	3,107	2,343	1,753	1,764	2,126	2,427
Total assets	10,645	11,647	12,912	12,656	12,160	11,880	9,538	8,187	7,926	8,113	8,401
Accounts payable	226	355	783	499	546	780	272	265	281	384	414
Current debt	0	1,379	275	0	10	6	7	0	0	0	670
Other current liabilities	382	420	744	633	756	781	728	557	682	876	960
Total current liabilities	609	2,154	1,803	1,132	1,311	1,567	1,006	822	963	1,260	2,044
Long-term debt	3,941	3,064	4,348	4,379	3,904	4,349	3,655	3,578	3,740	3,890	3,371
Other LT liabilities	913	1,016	1,091	1,118	894	1,045	582	532	403	403	403
Non-controlling int	0	0	0	12	12	10	11	8	24	24	24
Shareholders' equity	5,182	5,412	5,670	6,014	6,038	4,909	4,283	3,247	2,796	2,536	2,559
Total liabilities and equity	10,645	11,647	12,912	12,656	12,160	11,880	9,538	8,187	7,926	8,113	8,401
Total debt	3,941	4,443	4,624	4,380	3,914	4,355	3,662	3,579	3,740	3,890	4,040
Net debt	2,850	3,642	4,084	3,601	3,407	3,819	3,387	3,283	3,665	3,791	3,834
Debt/capital	43%	45%	45%	42%	39%	47%	46%	52%	57%	61%	61%
Debt/equity	76%	82%	82%	73%	65%	89%	85%	110%	134%	153%	158%
Debt turns	**2.9**	**3.1**	**2.5**	**2.2**	**2.4**	**2.5**	**3.2**	**5.8**	**6.6**	**4.7**	**3.9**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
National Oilwell Varco

Reuters	Bloomberg
NOV.N	NOV UN

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Research Analyst
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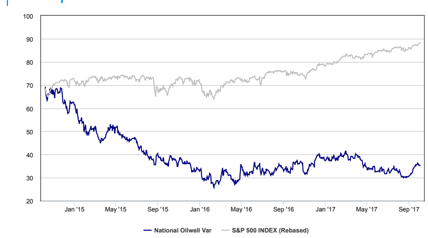
Price at 5 Oct 2017 (USD)	36.03
Price target	39.00
52-week range	41.62 - 29.94

Price/price relative



Performance (%)	1m	3m	12m
Absolute	14.8	3.9	-0.8
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	13,574.3
Shares outstanding (m)	376.8
Free float (%)	100
Volume (5 Oct 2017)	1,193,012
Option volume (und. shrs., 1M avg.)	1,124,105

Source: Deutsche Bank

National Oilwell Varco (NOV)

Acquisition Enabled Earnings Growth

Initiating coverage with a Hold rating and a $39 price target

National Oilwell Varco is among the best-in-class for free cash flow, balance sheet strength, acquisition enabled earnings growth, and management. The company has done over 120 acquisitions over the past decade that largely focused on enhancing its earnings power within its Wellbore Technologies and Completion & Production segments. Earnings have pivoted, a US onshore recovery has emerged, and irrational earnings expectations have been reset lower providing for a significantly better setup for the stock.

Acquisition enabled earnings growth

NOV should benefit from a US onshore levered margin expansion that has been enabled by cost reductions, improved manufacturing efficiencies, and an inflection in US drilling activity that is driving NOV's traditional manufacturing businesses related to rig upgrades, frac reactivations, and frac newbuilds, as well as its Wellbore Technologies segment that is 58% levered to North America. Helping restore its earnings power is an acquisition strategy that has been disproportionately focused on businesses unrelated to its Rig Systems segment. Acquiring geographically captive niche technologies, NOV is growing its global completions, directional drilling and precision well placement capabilities. It also continues to invest in its fiberglass pipe business, which is addressing the top of mind problem of corrosion and production.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.06	-0.17A	0.03
2Q EPS	-0.30	-0.14A	0.08
3Q EPS	-0.34	-0.08	0.18
4Q EPS	-0.15	-0.01	0.26
FY EPS (USD)	-0.85	-0.40	0.55
OLD FY EPS (USD)	–	–	–
% Change	–	–	–
P/E (x)	–	–	65.6
DPS (USD)	0.61	0.20	0.20
Dividend Yield (%)	1.9	0.6	0.6
Revenue (USDm)	7,251.0	7,403.2	9,034.2

Source: Deutsche Bank estimates, company data

Valuation

We are initiating coverage of National Oilwell Varco with a $39 price target. This is 11.8x our estimate of the company's normalized EPS power of $3.30 per share, which is in-line with the 11.8x five-year average multiple leading up to the 2014 collapse in oil prices.

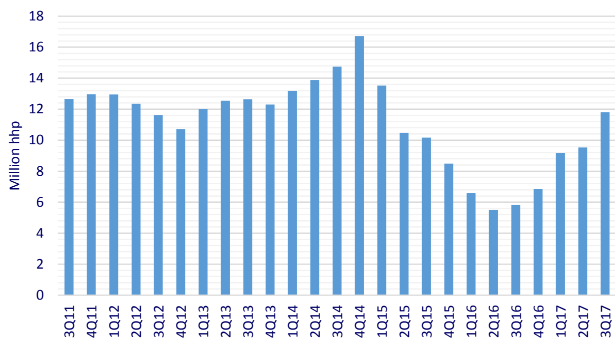
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a slowing in the retooling efforts in the US land and pressure pumping markets, and 4) further disruptions to the retooling efforts internationally.

Key investment themes

US pressure pumping reactivations and eventual newbuilds

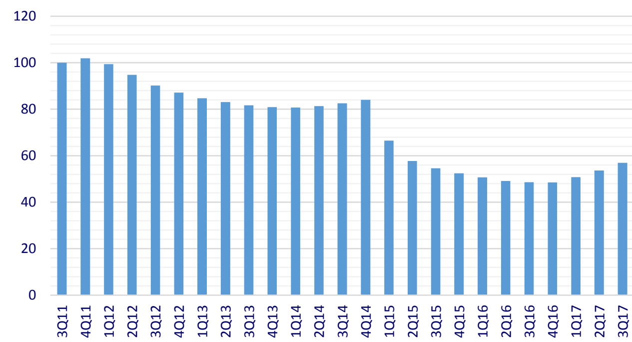
1Q18 is the earliest a customer can get a frac spread from NOV. The company sold 260,000 hhp of new frac equipment in 1H17 and had 6-8 ongoing discussions with customers about additional newbuilds. The urgency of those discussions declined as oil prices drifted lower, but did not disappear. We expect new orders will continue build into year-end, albeit at a modest pace.

Figure 425: US frac demand



Source: IHS Markit, Deutsche Bank

Figure 426: US frac price index



Source: IHS Markit, Deutsche Bank

US land fleet upgrade driving some new order growth in Rig Systems

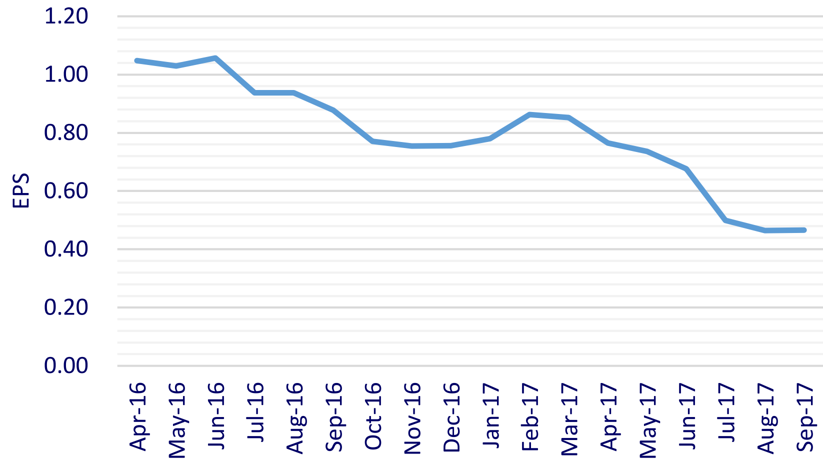
In 2Q17, land orders were 60% of the total new orders in the Rig Systems segment. We model total Rig Systems orders at about $530 million for 2017 and $766 million for 2018, which are small fractions of the $10-15 billion range set in 2013 and 2014, but we have seen the pivot in new orders and now some growth. A key driver is the super-spec upgrade and some of the private contractors retooling their fleets to remain competitive. While complete land rigs generate a solid double-digit margin for NOV, rig components are more lucrative and that is what NOV is pulling in. Top drives, solids control equipment, iron roughnecks, pipe racking and BOPs are all benefitting from the current upgrade trend. Top drives are the highest exposure due to the demand for high torque units with twin 660hp motors to accommodate for the longer laterals. We expect a few hundred more upgrades in 2018 alone.

The one negative is Helmerich & Payne, Precision Drilling and Patterson-UTI used almost exclusively NOV top drives (NBR uses its Canrig top drives). But Patterson has since acquired Warrior, which will fulfill Patterson's top drive requirements going forward.

In terms of complete land rig packages, we expect that demand to be small in 2018. Contractors generally need dayrates in the $24-25 kpd range to justify newbuilds, and rates are currently encountering some headwinds in the low $20s. While private contractors have a lower threshold, there is not an abundance of capital among them.

All-in, the US land rig market is experiencing a rapid upgrade cycle as contractors reposition themselves to ensure they have the most competitive tier 1 land rigs. Helmerich & Payne has identified 122 upgrade candidates in its fleet alone. Ultimately the US is a good opportunity, but the international retooling is better.

Figure 427: The irrational EPS expectations have been revised down



Source: Factset

International retooling slow to materialize, but Saudi Aramco stepping up

The international land rig retooling effort has been a lingering opportunity set that has yet to take-off materially. Timing has been a question, and buy-in is an issue. International contractors and operators do not buy into the value proposition of the more expensive high-specification rigs the same way US contractors and operators do. Thus the retooling effort has been sliding to the right for years. But there is a bright spot with Saudi Aramco. NOV is in the final stages of becoming the exclusive provider of the 50 newbuild land rigs stipulated under the joint venture agreement between Saudi Aramco and Nabors Industries. These rigs would be delivered over a period of ten years on a take-or-pay basis for $30-50 million apiece. NOV also intends to sell outside of Saudi Arabia provided the demand is there to retool, where the company already has a large Middle East installed base for its aftermarket business.

Cutting costs, more efficient infrastructure

Management has suggested it can restore its $6 per share of earnings power with $17 billion of revenues versus the $22 billion it took in 2014 when it achieved this earnings high water mark. Consolidating facilities and investing in more efficient manufacturing equipment that require less headcount is one of several cost cutting efforts the company has made to prime it for the eventual recovery. NOV has closed 350 locations (which does include sales offices and stocking centers) and has completed its effort to bring outsourcing in-house (maintained some outsourcing). While there is still some margin pressure in the Rig Systems business due to some legacy throughput, we expect strong incremental margins in its Wellbore Technologies and Completion & Production Solutions segments in 2018.

Infrastructure to support smaller scale deepwater field development

More of a longer-term story, NOV is performing a study for a customer for a field development plan in the Barents Sea that would potentially use one of its proprietary FPSOs that NOV has designed in partnership with GE. The

HoneyBee and MiniBee FPSOs have a capacity of 20-60 kb/d and are targeting markets where operators would do phased production on larger scale fields to achieve first oil faster to improve NPVs. Operators can tie-in future phases and perform more comprehensive well testing to optimize the larger FPSOs as they are built and brought on location. The company is also targeting the 400 or so undeveloped discoveries that are smaller, more marginal fields that are stranded assets.

The intended benefits are lower vessel construction cost and delivery in under three-years. The designs are 70% standardized and are about 30% cheaper. While NOV has not yet received the green light on its first vessel, we believe the concept of phased production appeals to operators. SBM Offshore has a competing design, but with a larger capacity of 150 kb/d.

The Seabox seawater injection system

One of NOV's latest entries into the subsea market is its seawater injection system called the Seabox. The Seabox injects seawater into injection wells to push oil out. As operators look to reduce overall offshore costs, this technology

Corrosion in the oilfield is top of mind

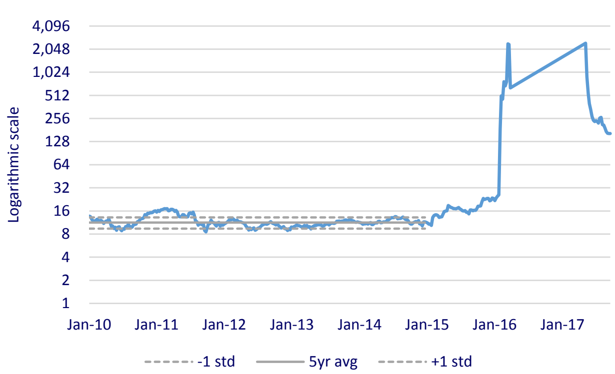
We expect to hear a lot more about corrosion in the coming years. Corrosion is one of the industry's biggest production challenges and is key focus for many private equities looking to find secular growth opportunities in oilfield services. NOV's Fiberglass pipe business is an opportunity in waiting, already representing about 15% of Completion & Production Solutions revenues. This will be top of mind for us as we look to define the addressable market.

Valuation and risks

We are initiating coverage of National Oilwell Varco with a $39 price target. This is 11.8x our estimate of the company's normalized EPS power of $3.30 per share, which is in-line with the 11.8x five-year average multiple leading up to the 2014 collapse in oil prices.

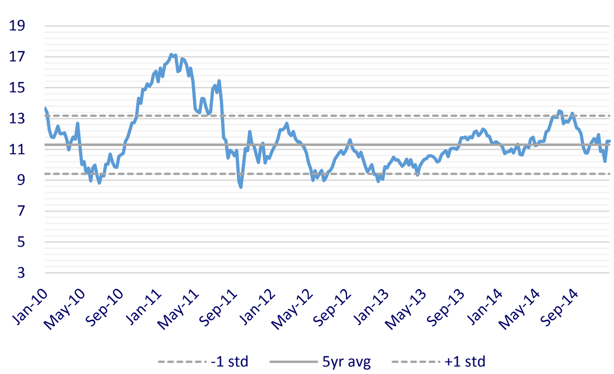
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a slowing in the retooling efforts in the US land and pressure pumping markets, and 4) further disruptions to the retooling efforts internationally.

Figure 428: The P/E valuation band has blown out



Source: Factset

Figure 429: The 5yr P/E leading up to 2014



Source: Factset

Company description

National Oilwell Varco (NOV) is a leading manufacturer of oilfield tools and equipment for both land and offshore applications. The company has four reporting segments including Rig Systems, Rig Aftermarket, Wellbore Technologies, and Completion & Production Solutions. The Rig Systems segment manufactures land rigs, complete offshore drilling packages, workover rigs, and a broad array of discrete rig components. The Rig Aftermarket segment provides spare parts (manufactured mainly by Rig Systems), technical support, field services, recertification and remote support.

Figure 430: Company reporting segments

National Oilwell Varco

Rig Systems
- Land rigs - "Ideal Rig" series
- Offshore rig packages
- Workover rigs

Rig Aftermarket
- Spare parts
- Technical support
- Field service and repair
- Recertification
- Remote support
- Condition monitoring
  - RIGSENTRY™ - BOP predictive analytics

Rig Systems, cont'd
- Drilling rig components
  - Instrumentation and control systems
  - Power systems - AC drive, SCR drive
  - Hoisting systems - derricks, drawworks
  - Rotating systems - top drives
  - Fluids systems - mud pumps
  - Pressure control - BOPs and control systems
  - Pipe handling equipment
    - Vertical and horizontal pipe racking
    - Iron roughnecks
    - Casing running tools (CRT)

  Pipe handling tools
  - Motion compensation (offshore)

Wellbore Technologies
- Drill pipe, heavy-weight drill pipe, drill subs
- Premium tubular connections
- Tubular inspection, repair and coating
- Downhole drilling motors and power sections
- MWD sensors and rotary steerable systems
- IntelliServ wired pipe
- Solids control equipment, waste management
- Drill bits and borehole enlargement tools
- Drilling tools, fishing tools, coiled tubing tools
- Agitator systems - BHA friction reducing tools
- Drilling and completion fluids, mud chillers
- Managed pressure drilling (MPD) systems
- Coring services
- Water services, pad preparation
- Portable power generation
- Drilling automation and optimization
- Instrumentation, measuring and monitoring

Completion & Production Solutions
- Pressure pumping equipment
- Completion tools
  - Sliding sleeve, dissolving frac balls
  - Cementing tools
- Coiled tubing units
- Wireline units
- FPSO solutions (HoneyBee)
  - Mooring systems
  - Subsea flexible pipe
  - Topside processing equipment
  - Lifting and handling equipment
  - Fiberglass pipe
- Onshore production solutions
- Artificial lift
- Fiberglass pipe
- Processing equipment
- Process flow technologies

Source: Deutsche Bank

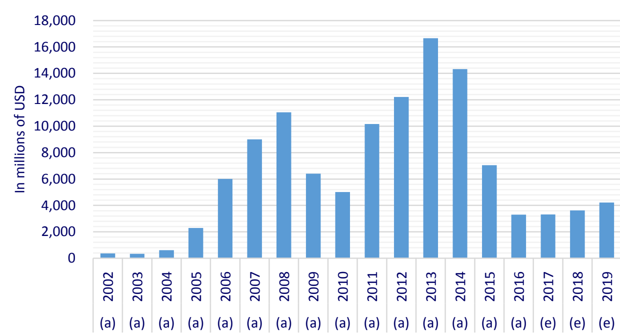
Wellbore Technologies is a leading provider of directional drilling tools, drilling and completion fluids, drill bits, solids control equipment, waste management, tubular coating and inspection, and drill pipe. The Completion & Production Solutions segment manufactures pressure pumping equipment, completion tools, coiled tubing, and wireline units. It also provides floating production solutions, flexible pipe, fiberglass pipe, subsea products, artificial lift and processing equipment.

Principal Sources and Uses of Cash Flow

Principal source of cash has shifted away from offshore rig packages

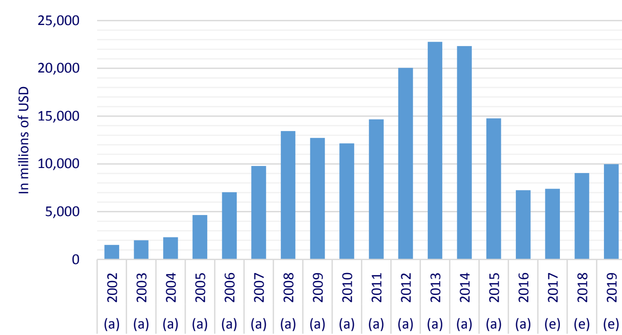
For years, NOV has aligned its high competency in manufacturing with an acquisition strategy that has concentrated on bringing niche technologies in-house that help it establish a core market presence in disciplines the company thinks are primed for growth. Through 2005, and culminating with the Varco International merger, NOV established a strategic foothold in the offshore capital equipment market. Over the next ten years, NOV took over 70% of the market share in deepwater drilling packages in what became the largest deepwater rig expansion in history.

Figure 431: Total backlog



Source: Company reports, Deutsche Bank

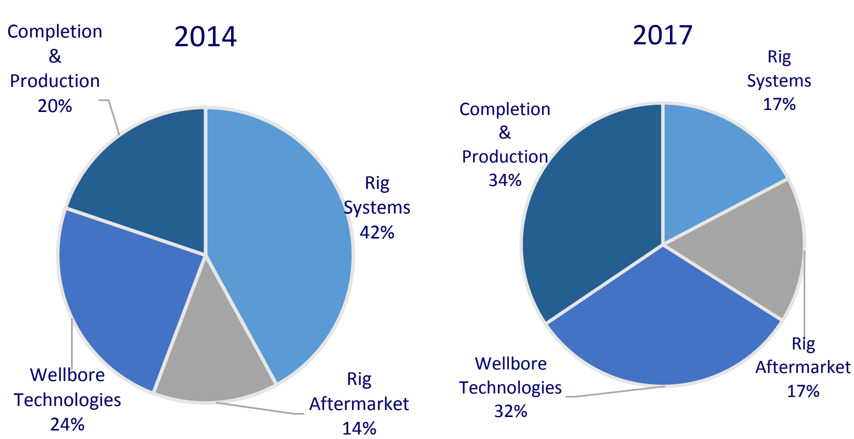
Figure 432: Total revenues



Source: Company reports, Deutsche Bank

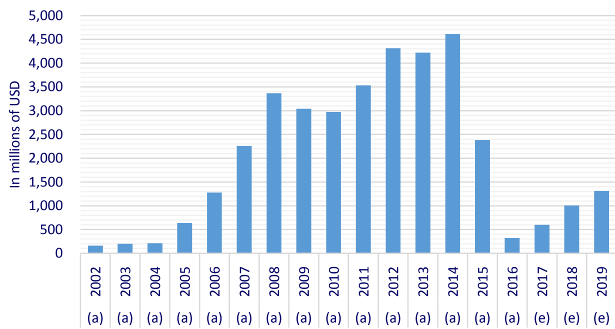
During that same period, NOV also took a leading market share in the replacement of the aging jackup fleet. Accordingly, NOV became synonymous with offshore rig building as its surging backlog reached a 90% gearing to the offshore markets by 2014.

Figure 433: Revenues by reporting segment (2017 is DB estimate)



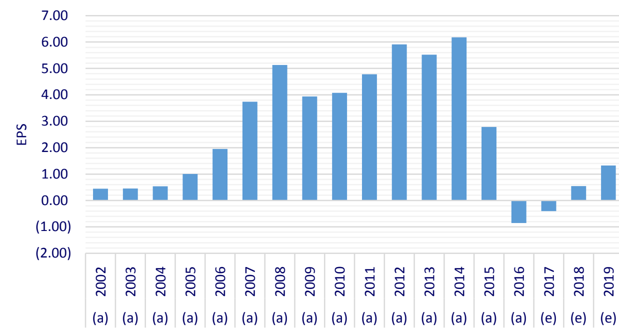
Source: Company reports, Deutsche Bank

Figure 434: Consolidated EBITDA



Source: Company reports, Deutsche Bank

Figure 435: Annual EPS



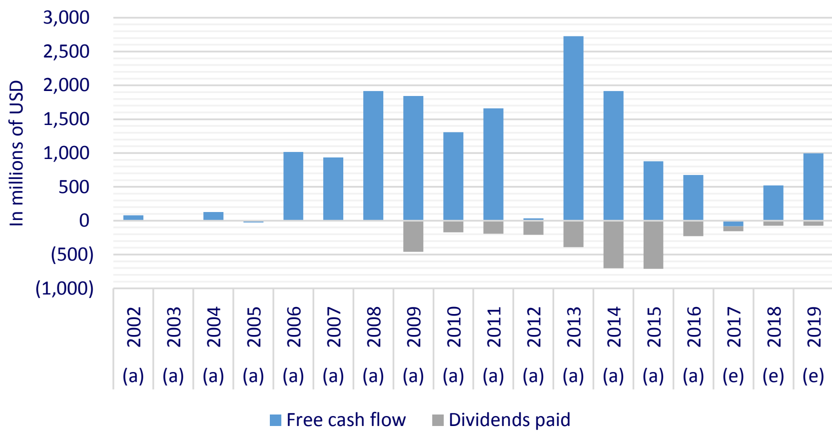
Source: Company reports, Deutsche Bank

Overshadowed by its leverage to the deepwater, NOV was also benefitting from the proliferation of capital that was investing in the development of US tight oil reserves. Since the merger with Varco International, NOV had been harvesting the expansion in the deepwater, but concentrating its acquisition efforts outside of Rig Systems. Since the Varco merger, NOV closed on more than 120 acquisitions totaling over $16 billion, with a disproportionately large percentage of that unrelated to Rig Systems. This helped position the company to benefit from the unprecedented expansion in horizontal drilling, but it was still second to the offshore. At the peak in 2014, NOV derived about two-thirds of its revenues from the offshore versus one-third from onshore.

Due to the severity of the downturn in the deepwater, which is the worst the industry has ever experienced, NOV's strategy would seemingly have to pivot fast to accommodate the lost earnings from the offshore. But while these earnings are unlikely to be restored organically anytime soon, NOV's acquisition strategy pivoted years ago towards directional drilling, completions, fiberglass pipe, FPSO solutions and processing equipment to name a few. The company had already aligned its acquisition strategy to address the increasing complexities of longer laterals, the increased demand for drilling efficiencies, and demand to reduce non-productive time (NPT).

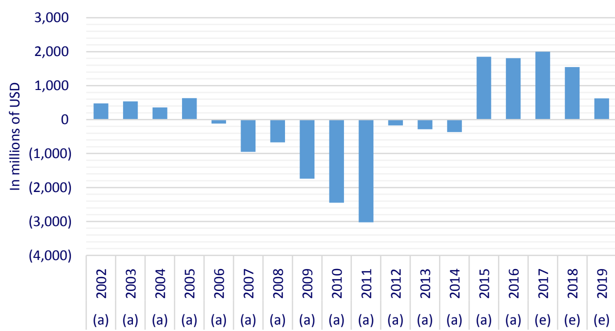
Going forward, NOV intends to continue its acquisition strategy and grow its capabilities in completion tools, directional drilling, floating production solutions, and new subsea technologies. Management also intends to focus once again on the newbuild cycle for hydraulic fracturing equipment and the upgrade cycle for AC-electric land rigs in the US and the retooling of international land rigs. NOV's floating production storage and offloading (FPSO) solution still needs its first newbuild, and NOV is engaged in a study that applies its HoneyBee FPSO design to the Barents Sea.

Figure 436: Industry leading free cash flow performance



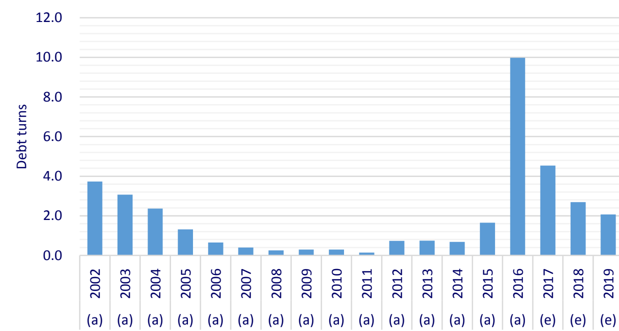
Source: Company reports, Deutsche Bank

Figure 437: Net debt



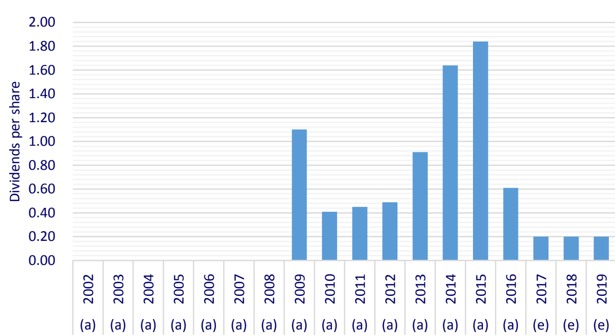
Source: Company reports, Deutsche Bank

Figure 438: Debt turns



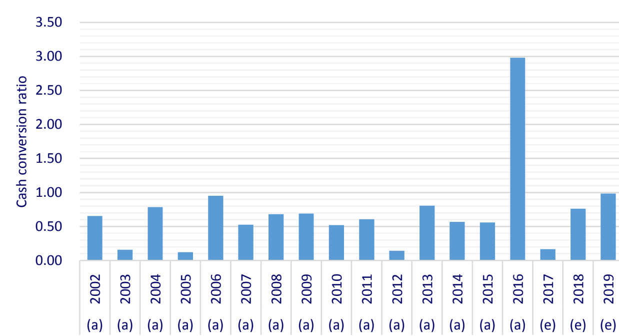
Source: Company reports, Deutsche Bank

Figure 439: Dividends



Source: Company reports, Deutsche Bank

Figure 440: Cash conversion (CFO/EBITDA)



Source: Company reports, Deutsche Bank

Figure 441: Income Statement

	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:								
Rig Systems	7,077	8,450	9,848	6,964	2,386	1,418	1,316	1,356
Rig Aftermarket	2,138	2,692	3,222	2,515	1,416	1,372	1,495	1,635
Wellbore Technologies	5,184	5,109	5,722	3,718	2,199	2,587	3,362	3,891
Completion & Production	3,994	4,309	4,645	3,365	2,241	2,827	3,858	4,178
Eliminations	1,648	2,207	(1,109)	(1,805)	(991)	(800)	(996)	(1,099)
Total revenue	20,041	22,767	22,328	14,757	7,251	7,403	9,034	9,962
Segment EBIT:								
Rig Systems	1,685	1,615	1,996	1,318	221	40	54	85
Rig Aftermarket	594	729	882	617	294	307	364	416
Wellbore Technologies	983	854	1,047	162	(294)	(81)	250	436
Completion & Production	774	695	700	286	8	163	306	410
Eliminations	(348)	(425)	(793)	(749)	(610)	(522)	(651)	(718)
EBIT	3,688	3,468	3,832	1,634	(381)	(93)	323	629
Interest (expense)	(48)	(111)	(105)	(103)	(105)	(101)	(97)	(97)
Interest income	10	12	18	14	15	16	8	15
Equity income	58	63	58	13	(21)	0	0	0
Other income	(60)	(32)	(33)	(114)	(53)	(13)	(16)	(16)
PBT	3,648	3,400	3,770	1,444	(545)	(191)	218	531
Income tax (expense)	(1,130)	(1,032)	(1,112)	(362)	221	38	(15)	(37)
Non-controlling interest	8	(1)	(5)	0	4	1	4	4
Preferred dividends	0	0	0	0	0	0	0	0
Net income (operating)	2,525	2,367	2,653	1,082	(320)	(152)	207	498
Discontinued ops	0	(51)	11	0	0	0	0	0
Unusual after-tax	(65)	11	(162)	(1,851)	(2,092)	(81)	0	0
Net income (GAAP)	**2,460**	**2,327**	**2,502**	**(769)**	**(2,412)**	**(233)**	**207**	**498**
Operating EPS	**5.91**	**5.52**	**6.18**	**2.79**	**(0.85)**	**(0.40)**	**0.55**	**1.32**
GAAP EPS	5.76	5.43	5.83	(1.98)	(6.42)	(0.62)	0.55	1.32
DPS	0.49	0.91	1.64	1.84	0.61	0.20	0.20	0.20
Diluted shares	427	428	430	388	376	377	377	377
EBITDA	**4,316**	**4,223**	**4,614**	**2,381**	**322**	**598**	**1,007**	**1,313**
EBITDA margin	21.5%	18.5%	20.7%	16.1%	4.4%	8.1%	11.1%	13.2%
EBIT margin	18.4%	15.2%	17.2%	11.1%	-5.3%	-1.3%	3.6%	6.3%
Tax rate	31.0%	30.4%	29.5%	25.1%	40.6%	19.8%	6.9%	6.9%
Total backlog	**12,220**	**16,662**	**14,322**	**7,048**	**3,306**	**3,320**	**3,621**	**4,216**
Rig Systems	10,876	15,028	12,542	6,079	2,488	2,086	2,067	2,384
Completion & Production	1,344	1,634	1,780	969	818	1,234	1,554	1,832
New orders	**10,043**	**14,210**	**8,883**	**2,313**	**1,614**	**2,675**	**3,652**	**4,007**
Rig Systems	7,829	11,537	6,203	993	463	528	766	1,121
Completion & Production	2,214	2,673	2,680	1,320	1,151	2,147	2,886	2,886

Source: Deutsche Bank

Figure 442: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	2,525	2,367	2,653	1,082	(320)	(152)	207	498
Depreciation	628	755	782	747	703	691	684	684
Deferred tax	(97)	(333)	(300)	(258)	(198)	19	0	0
Chg in receivables	(517)	(493)	(153)	1,091	845	(287)	(251)	(126)
Chg in inventories	(1,061)	396	(710)	410	782	(267)	(57)	85
Chg in payables	(19)	9	95	(570)	(243)	160	65	54
Other	(839)	696	247	(1,170)	(609)	(65)	118	97
Cash from operations	620	3,397	2,614	1,332	960	99	766	1,292
Capital expenditures	(583)	(669)	(699)	(453)	(284)	(180)	(243)	(295)
Free cash flow	37	2,728	1,915	879	676	(82)	523	997
Acquisitions	(2,880)	(2,397)	(291)	(86)	(230)	(82)	0	0
Asset sales	0	0	0	0	0	0	0	0
Dividends paid	(209)	(389)	(703)	(710)	(230)	(76)	(75)	(75)
ESPP | options	113	58	108	7	4	10	0	0
Equity issuance, net	0	0	(779)	(2,221)	0	0	0	0
Debt issuance, net	2,637	(1)	18	762	(900)	(503)	0	0
Other	86	118	(168)	(87)	8	41	0	0
Chg in cash	(216)	117	100	(1,456)	(672)	(691)	447	922
FCF per share	0	6	4	2	2	(0)	1	3
Capex / revenue	0	0	0	0	0	0	0	0
Capex / depreciation	1	1	1	1	0	0	0	0

Source: Deutsche Bank

Figure 443: Balance Sheet

In millions of USD	(a) 2012	(a) 2013	(a) 2014	(a) 2015	(a) 2016	(e) 2017	(e) 2018	(e) 2019
Cash and equivalents	3,319	3,436	3,536	2,080	1,408	717	1,164	2,086
Accounts receivable	4,320	4,896	4,416	2,926	2,083	2,364	2,614	2,741
Inventories	5,891	5,603	5,281	4,678	3,325	3,596	3,653	3,568
Costs in excess of billings	1,225	1,539	1,878	1,250	665	679	751	787
Other current assets	923	949	1,051	867	395	372	428	467
Total current assets	15,678	16,423	16,162	11,801	7,876	7,727	8,610	9,649
Net PP&E	2,945	3,408	3,362	3,124	3,150	2,805	2,364	1,975
Goodwill	7,172	9,049	8,539	6,980	6,067	6,129	6,129	6,129
Deferred taxes	413	372	503	488	86	70	70	70
Intangibles	4,743	5,055	4,444	3,849	3,530	3,438	3,438	3,438
Investment in affiliates	393	390	362	327	307	306	306	306
Other assets	140	115	190	156	124	176	203	221
Total assets	31,484	34,812	33,562	26,725	21,140	20,652	21,120	21,788
Accounts payable	1,200	1,275	1,189	623	414	526	591	645
Accrued expenses	2,571	2,763	3,518	2,284	1,568	1,738	1,998	2,180
Billings in excess of costs	1,189	1,771	1,775	785	440	361	393	458
Current debt	1	0	152	2	506	6	6	6
Other current liabilities	688	869	740	555	119	83	95	104
Total current liabilities	5,649	6,678	7,374	4,249	3,047	2,714	3,083	3,393
Long-term debt	3,148	3,149	3,014	3,928	2,708	2,708	2,708	2,708
Deferred taxes	1,997	2,292	1,972	1,805	1,064	999	999	999
Other LT liabilities	334	363	430	283	318	307	307	307
Non-controlling int	117	100	80	77	63	67	63	59
Shareholders' equity	20,239	22,230	20,692	16,383	13,940	13,857	13,960	14,322
Total liabilities and equity	31,484	34,812	33,562	26,725	21,140	20,652	21,120	21,788
Total debt	3,149	3,149	3,166	3,930	3,214	2,714	2,714	2,714
Net debt	(170)	(287)	(370)	1,850	1,806	1,997	1,550	628
Debt/capital	13%	12%	13%	19%	19%	16%	16%	16%
Debt/equity	16%	14%	15%	24%	23%	20%	19%	19%
Debt turns	**0.7**	**0.7**	**0.7**	**1.7**	**10.0**	**4.5**	**2.7**	**2.1**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Noble Corp.

Reuters	Bloomberg
NE.N	NE US

David Havens
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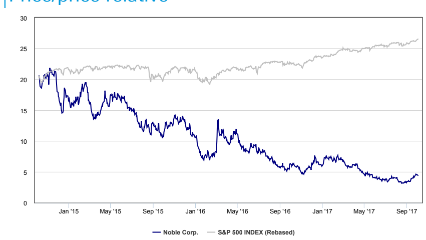
Price at 5 Oct 2017 (USD)	4.50
Price target	4.00
52-week range	7.69 - 3.16

Price/price relative



Performance (%)	1m	3m	12m
Absolute	28.4	12.3	-26.2
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Grinding Out Debt Maturities

Initiating coverage with a Hold rating and an $4 price target

While the deepwater markets are pivoting, we believe the recovery will be slow and laborious. The extent of the supply demand imbalance and the stresses on the balance sheets industry-wide are going to keep fierce pricing tactics in play for a number of years in our view. While we believe the alpha short opportunity is largely used up, the upside in our view is limited as EBITDA erodes even lower for the next two years. One more source of volatility for NE is the risk related to the creditors of Paragon Offshore regarding any fraudulent conveyance claims against NE. We believe this combined with the string of debt maturities each year totaling over $800 million through 2021 will keep investors on the sidelines for now.

Noble among the least proactive in managing its balance sheet

While many of Noble's peers opted to refinance and/or pay down debt or even issue equity at considerably higher stock prices to manage leverage and debt maturities in the most challenging market ever experienced, NE has not tapped capital markets and has instead opted to grind the maturities out as they come. This has made the markets uneasy in our view as the uncertainty regarding the scope of the recovery and the timing pushes investors toward more fiscally stable balance sheets. The uncertainty related to the Paragon creditors only adds to the uneasiness.

Stock & option liquidity data

Market Cap (USDm)	1,101.0
Shares outstanding (m)	244.7
Free float (%)	–
Volume (5 Oct 2017)	1,839,545
Option volume (und. shrs., 1M avg.)	757,584

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.32	-0.17A	-0.38
2Q EPS	0.01	-0.32A	-0.35
3Q EPS	-0.23	-0.39	-0.33
4Q EPS	-0.15	-0.41	-0.32
FY EPS (USD)	-0.05	-1.29	-1.39
OLD FY EPS (USD)	-0.05	–	–
% Change	-4.7%	–	–
P/E (x)	–	–	–
DPS (USD)	0.19	0.00	0.00
Dividend Yield (%)	2.4	0.0	0.0
Revenue (USDm)	1,892.7	1,193.6	1,122.5

Source: Deutsche Bank estimates, company data

Valuation & Risks

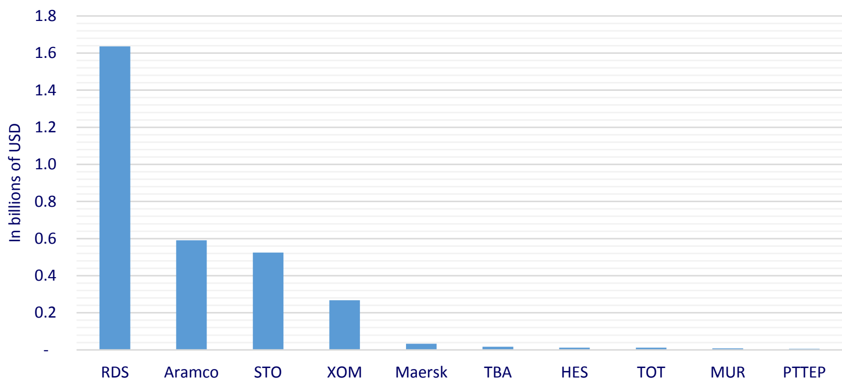
We are initiating coverage with a $4 price target. This is 4.5x our estimate of the company's normalized EBITDA of $1.1 billion, which is two-turns below the 6.5x ten-year average multiple. The company is currently trading at 12x our fiscal 2018 EBITDA estimate of $0.4 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance. The debt burden in the coming years is another headwind.
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) increased flow of capex directed away from the offshore and toward onshore operations.
Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Key investment themes

Highest customer concentration among its peers

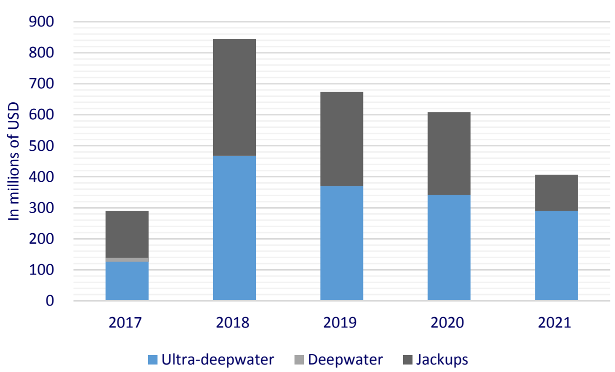
Noble's backlog is $3.1 billion, which is down 73% from the $11.5 billion in January 2009. The standout customer is Royal Dutch Shell, which is 53% of Noble's total backlog. Noble's top five customers are 98% of the total backlog. About 40% of its ultra-deepwater availability and 46% of its jackup availability are contracted for 2018.

Figure 444: Backlog by customer



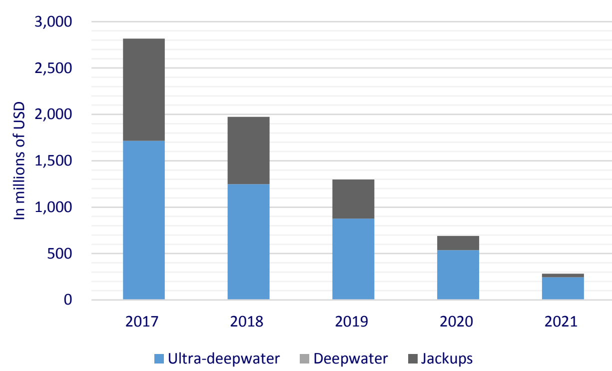
Source: Company reports, Deutsche Bank

Figure 445: Revenues in backlog



Source: Company reports, Deutsche Bank

Figure 446: Year-end backlog

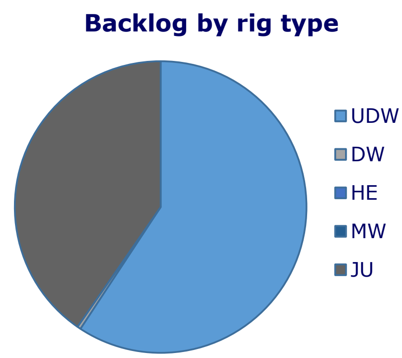


Source: Company reports, Deutsche Bank

Figure 447: Noble Corporation backlog details

Revenue in backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	127	468	370	342	290
Deepwater	12	0	0	0	0
Harsh-environment					
Midwater					
Jackups	151	377	304	267	116
Total backlog	**290**	**845**	**674**	**609**	**406**

Total backlog	Abbrev	($bn)
Ultra-deepwater	UDW	1.8
Deepwater	DW	0.0
Harsh-environment	HE	
Midwater	MW	
Jackups	JU	1.3
Total backlog		**3.1**



Days committed	2017	2018	2019	2020	2021
Ultra-deepwater	37%	40%	35%	33%	27%
Deepwater	50%	0%	0%	0%	0%
Harsh-environment					
Midwater					
Jackups	77%	46%	27%	21%	14%
Total backlog	**58%**	**40%**	**28%**	**25%**	**19%**

Year-end backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	1,715	1,248	878	536	245
Deepwater	0	0	0	0	0
Harsh-environment					
Midwater					
Jackups	1,103	726	421	155	38
Total backlog	**2,818**	**1,973**	**1,299**	**690**	**284**

	2017	2018	2019
Total debt	4,043	3,793	3,593
Debt / YE backlog	**1.4**	**1.9**	**2.8**

Backlog by customer ($m	#1	#2	#3	#4	#5
Ultra-deepwater	**RDS**	**XOM**	**MUR**		
Backlog	1,631	203	8		
% of backlog	89%	11%	0%		
Deepwater	**HES**				
Backlog	12				
% of backlog	100%				
Harsh-environment					
Backlog					
% of backlog					
Midwater					
Backlog					
% of backlog					
Jackups	**Aramco**	**STO**	**XOM**	**Maersk**	**TBA**
Backlog	591	525	65	33	18
% of backlog	47%	42%	5%	3%	1%

Top 5 customers in backlog		Percent	$bn
RDS	#1	53%	1.6
Aramco	#2	19%	0.6
STO	#3	17%	0.5
XOM	#4	9%	0.3
Maersk	#5	1%	0.0
Other		**2%**	**0.1**

Fleet composition	2017	2018	2019
Ultra-deepwater	12	12	12
Deepwater	2	2	2
Harsh-environment			
Midwater			
Jackups	14	14	14
Total in fleet	**28**	**28**	**28**

Source: Company reports, Deutsche Bank

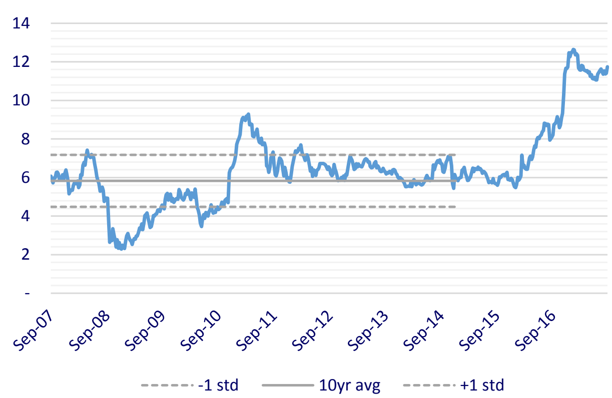
Valuation and risks

We are initiating coverage with a $4 price target. This is 4.5x our estimate of the company's normalized EBITDA of $1.1 billion, which is two-turns below the 6.5x ten-year average multiple. The company is currently trading at 12x our fiscal 2018 EBITDA estimate of $0.4 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance. The debt burden in the coming years is another headwind.

In terms of steel value, we assess the trough net asset value at $3.25 per share, which assumes the market endures another three years of high volumes of cold-stacking once contracts expire and leading edge market rates that stay at breakeven levels ($160-170 kpd).

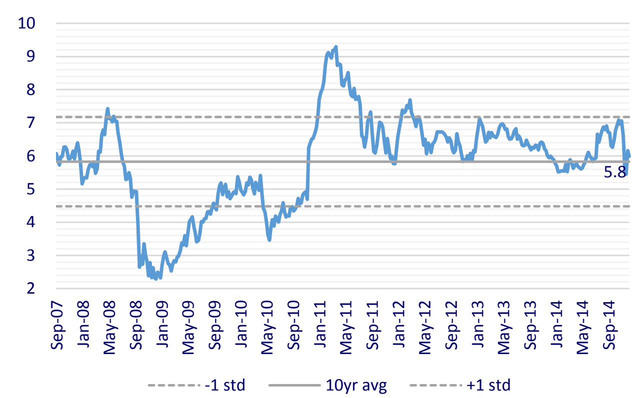
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) fraudulent conveyance risk related to Paragon Offshore, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Figure 448: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 449: The 5yr EV/EBITDA leading up to 2014



Source: Factset

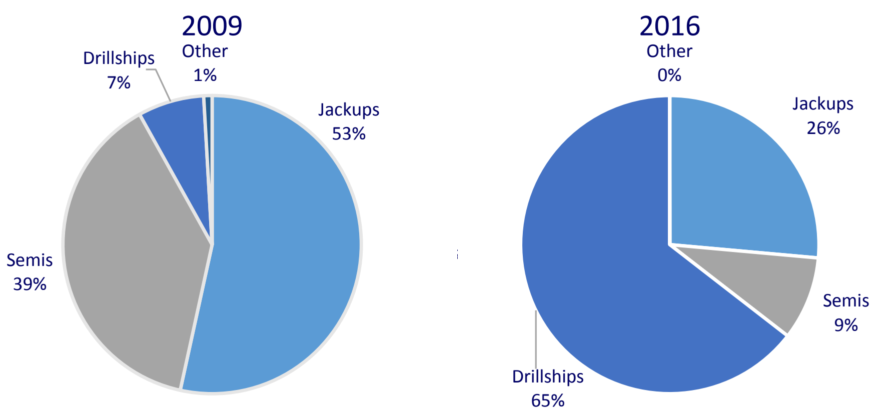
Paragon Offshore creditor risk

Noble completed the spin-off of its standard jackups and floaters in 2014 in a new publically traded company called Paragon Offshore. Paragon filed for relief under Chapter 11 bankruptcy in 2016 and in May 2017 filed a plan with its creditors that included a $10 million litigation trust to pursue litigation against Noble, most likely for fraudulent conveyance.

Company description

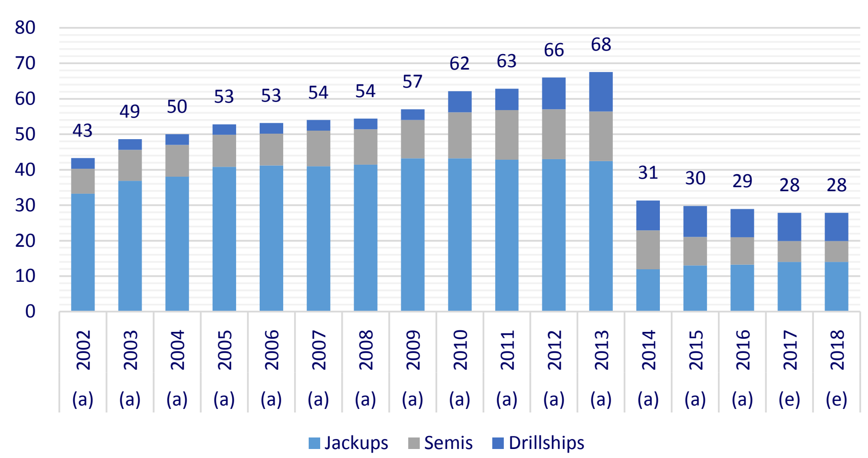
Noble Corporation (NE) is a contract drilling company with a fleet of 28 mobile offshore drilling rigs including 12 ultra-deepwater floaters, two deepwater floaters, and 14 jackups. Since 2008, the company has undertaken several initiatives to reposition itself competitively in the ultra-deepwater and high-specification jackup markets. Noble spent approximately $4.3 billion on the construction of eight ultra-deepwater floaters and about $2.0 billion on seven newbuild jackups. In 2014, the company spun-off its standard specification jackups and floaters into a publically traded company, Paragon Offshore.

Figure 450: Revenues by rig type



Source: Company reports, Deutsche Bank

Figure 451: Change in fleet size and mix



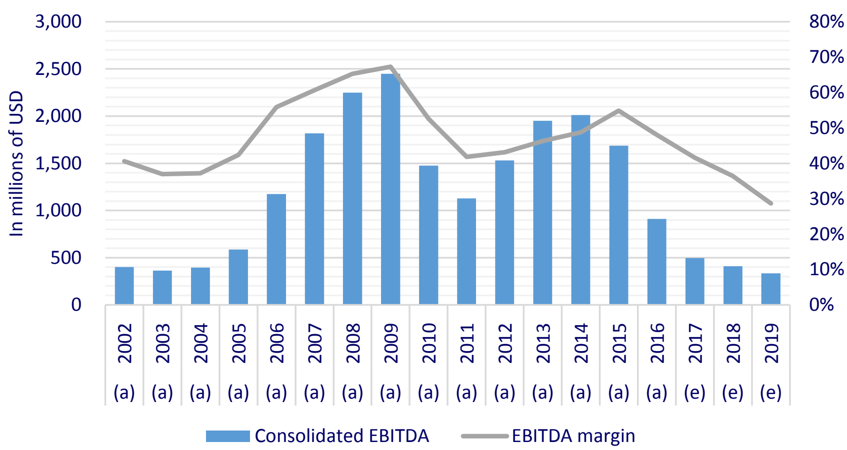
Source: Company reports, Deutsche Bank

Principal Sources and Uses of Cash Flow

Ultra-deepwater and high-specification jackups driving NE's earnings

Noble's principal source of cash flow is the ultra-deepwater and high-specification jackup market. Like most of its peers, Noble's earnings power has diminished as the industry copes with a severe supply demand imbalance in the deepwater that will likely impair dayrates for several more years. NE achieved its highest EBITDA of $2.45 billion in 2009 and we expect that to erode to about $320 million by 2019. Using a dayrate recovery to $300 kpd for an ultra-deepwater drillship, we expect NE can have a normalized EBITDA of about $1.1 billion, but not prior to 2020 in our view.

Figure 452: EBITDA eroding lower

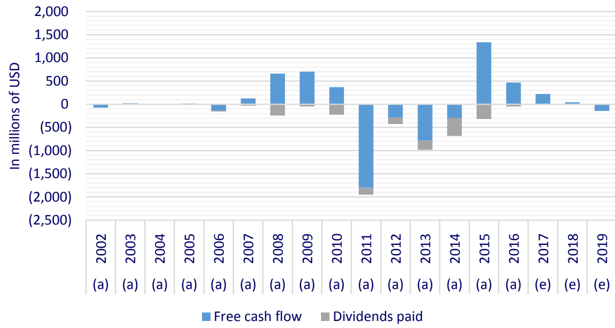


Source: Company reports, Deutsche Bank

Newbuild program is complete, no more funding for new rigs

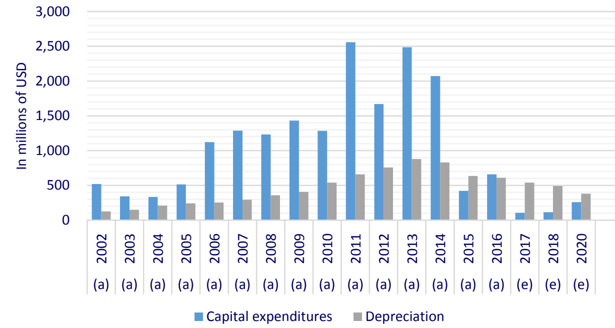
Noble spent over $6 billion on newbuilds since 2008, which ended with the delivery of the jackup Noble Lloyd Noble in 2016. While some of its peers are looking to replenish earnings through M&A, we do not expect NE to be active in this market. Debt maturities are the primary use of capital with over $800 million total due over a series of maturities though 2021. The company has been among the least proactive in managing its debt maturities and is now looking to grind them out as they come. In 2018, $250 million is due followed by $200 million in 2019.

Figure 453: Free cash flow and dividends



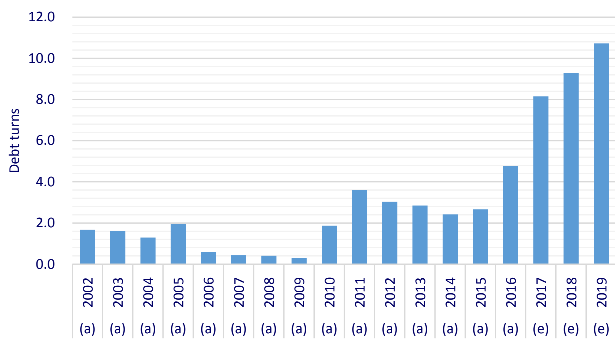
Source: Company reports, Deutsche Bank

Figure 454: Capex trend



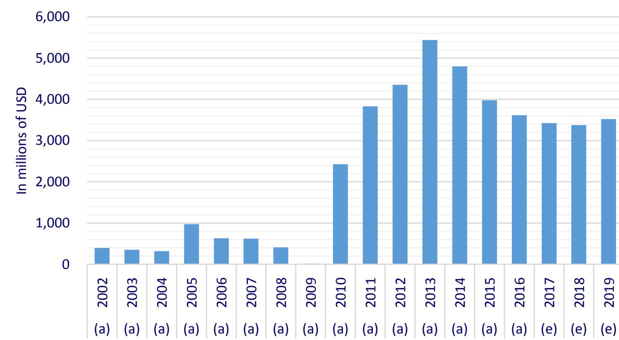
Source:
Company reports, Deutsche Bank

Figure 455: Debt turns



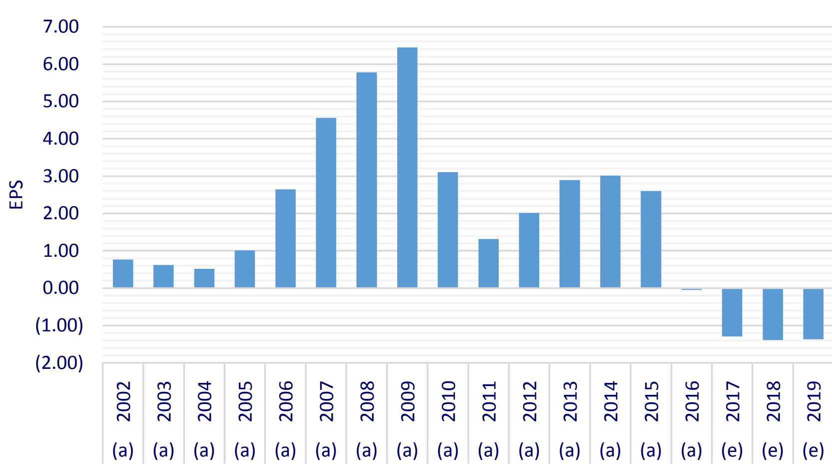
Source: Company reports, Deutsche Bank

Figure 456: Net debt



Source: Company reports, Deutsche Bank

Figure 457: EPS trend



Source: Company reports, Deutsche Bank

Figure 458: Fleet profile

Rig name	Water depth (ft)	Rig type	Year in service	Rig design	Backlog (yrs)	Backlog ($m)
Ultra-deepwater (12):						
Noble Bob Douglas	10,000	DS-DP	2013	GustoMSC P10000	3.5	210.9
Noble Don Taylor	10,000	DS-DP	2013	GustoMSC P10000	1.4	254.5
Noble Sam Croft	10,000	DS-DP	2014	GustoMSC P10000	-	-
Noble Tom Madden	10,000	DS-DP	2014	GustoMSC P10000	-	-
Noble Globetrotter I	10,000	DS-DP	2011	STX-Huisman GT-10000	4.8	484.3
Noble Globetrotter II	10,000	DS-DP	2013	STX-Huisman GT-10000	6.0	555.6
Noble Bully I	8,200	DS-DP	2011	GustoMSC PRD12,000	-	-
Noble Bully II	8,250	DS-DP	2011	GustoMSC PRD12,000	4.6	337.0
Noble Danny Adkins	12,000	6th	1999/2009	Noble Modified Bingo 9000	-	-
Noble Jim Day	12,000	6th	1999/2010	Noble Modified Bingo 9000	-	-
Noble Dave Beard	10,000	6th	1986/2009	F&Gn 9500 Enhanced Pacesetter	-	-
Noble Clyde Boudreau	10,000	5th	1987/2007	F&Gn 9500 Enhanced Pacesetter	-	-
Deepwater (2):						
Noble Amos Runner	8,000	4th	1982/1999	Noble EVA-4000	-	-
Noble Paul Romano	6,000	4th	1981/1998	Noble EVA-4000	0.3	12.1
Jackups (14):						
Noble Lloyd Noble	492	IC	2016	GustoMSC CJ70-X150A	3.2	524.9
Noble Hans Deul	400	IC	2009	Friede & Goldman JU-2000E	0.2	5.1
Noble Houston Colber	400	IC	2014	Friede & Goldman JU-3000N	-	-
Noble Mick O Brien	400	IC	2013	Friede & Goldman JU-3000N	-	-
Noble Regina Allen	400	IC	2013	Friede & Goldman JU-3000N	2.0	64.6
Noble Roger Lewis	400	IC	2007	Friede & Goldman JU-2000E	4.5	258.4
Noble Sam Hartley	400	IC	2014	Friede & Goldman JU-3000N	0.3	11.5
Noble Sam Turner	400	IC	2014	Friede & Goldman JU-3000N	0.9	33.4
Noble Scott Marks	400	IC	2009	Friede & Goldman JU-2000E	4.8	277.8
Noble Tom Prosser	400	IC	2014	Friede & Goldman JU-3000N	0.1	5.6
Noble Alan Hay	300	IC	1980/2005	Levingston Class 111-C	0.3	8.8
Noble David Tinsley	300	IC	1981/2010	Mitsui 300C-38	0.3	8.8
Noble Gene House	300	IC	1981/1998	Mitsui 300C-38	1.2	27.5
Noble Joe Beall	300	IC	1981/2004	Mitsui 300C-38	1.2	27.5

Source: Company reports, Deutsche Bank

Figure 459: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Jackups	1,879	1,200	1,008	1,254	1,577	1,211	644	484	580	601	623
Semis	1,353	1,106	1,237	1,530	1,515	1,265	698	166	45	38	38
Drillships	252	356	311	565	960	1,529	1,638	1,182	541	456	480
Other	32	35	60	82	52	16	0	0	0	0	0
Reimbursables	125	111	79	115	112	104	90	60	28	27	28
Total revenue	3,641	2,807	2,696	3,547	4,216	4,125	3,071	1,893	1,194	1,123	1,169
Op costs	1,111	1,239	1,477	1,917	2,147	2,008	1,308	914	633	649	769
G&A	80	92	91	100	118	107	77	69	65	65	65
D&A	408	540	659	759	879	829	634	611	541	492	433
EBIT	2,042	936	469	771	1,072	1,182	1,051	299	(45)	(84)	(98)
Interest (expense)	(2)	(9)	(56)	(86)	(106)	(155)	(214)	(223)	(329)	(352)	(337)
Interest income	7	10	4	5	4	1	7	0	0	0	0
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	0	0	(2)	0	1	(1)	(0)	0	9	11	11
PBT	2,047	936	415	690	970	1,027	844	76	(365)	(425)	(424)
Income tax (expense)	(361)	(144)	(88)	(142)	(162)	(179)	(130)	(16)	64	85	85
Non-controlling interest	0	(0)	8	(34)	(68)	(75)	(72)	(72)	(16)	(0)	4
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	1,686	793	335	514	740	772	642	(12)	(316)	(340)	(335)
Discontinued ops	0	0	0	0	0	(35)	0	0	(1)	0	0
Unusual after-tax	(7)	(19)	35	8	42	(729)	(131)	(944)	(275)	0	0
Net income (GAAP)	1,679	773	370	522	782	8	511	(956)	(592)	(340)	(335)
Operating EPS	6.45	3.11	1.32	2.01	2.90	3.01	2.60	(0.05)	(1.29)	(1.39)	(1.37)
GAAP EPS	6.42	3.03	1.46	2.05	3.06	(0.01)	2.06	(3.93)	(2.42)	(1.39)	(1.37)
DPS	0.18	0.89	0.60	0.55	0.77	1.50	1.28	0.19	0.00	0.00	0.00
Diluted shares	259	254	252	253	254	253	242	243	245	245	245
Consolidated EBITDA	2,450	1,476	1,128	1,530	1,951	2,011	1,686	910	496	409	335
EBITDA margin	67.3%	52.6%	41.8%	43.1%	46.3%	48.7%	54.9%	48.1%	41.6%	36.4%	28.7%
EBIT margin	56.1%	33.3%	17.4%	21.7%	25.4%	28.7%	34.2%	15.8%	-3.8%	-7.5%	-8.4%
Tax rate	18%	15%	21%	21%	17%	17%	15%	22%	18%	20%	20%
Utilization:											
Jackups	82%	79%	75%	83%	91%	85%	85%	83%	91%	97%	99%
Semis	99%	86%	82%	85%	81%	71%	64%	23%	17%	17%	17%
Drillships	83%	89%	59%	69%	81%	95%	100%	82%	60%	63%	82%
Dayrates ($000):											
Jackups	148	97	86	97	111	140	162	122	125	122	124
Semis	368	288	296	349	368	395	372	256	123	0	0
Drillships	254	256	242	279	334	440	503	491	314	250	202

Source: Deutsche Bank

Figure 460: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	1,686	793	335	514	740	772	642	(12)	(316)	(340)	(335)
Depreciation	408	540	659	759	879	829	634	611	541	492	433
Deferred tax	37	(41)	(82)	(20)	(16)	(11)	(36)	(190)	303	0	0
Chg in receivables	(3)	260	(200)	(157)	(205)	380	70	180	86	(14)	(10)
Chg in payables	(61)	177	61	(86)	(3)	(82)	(42)	(115)	(21)	7	18
Other	69	(74)	(14)	371	307	(110)	494	655	(265)	16	12
Cash from operations	2,137	1,654	759	1,382	1,702	1,778	1,762	1,128	328	161	117
Capital expenditures	(1,431)	(1,284)	(2,559)	(1,670)	(2,488)	(2,073)	(423)	(660)	(106)	(115)	(260)
Free cash flow	705	370	(1,800)	(288)	(785)	(295)	1,340	468	222	46	(143)
Acquisitions	0	(1,630)	0	0	0	0	0	0	0	0	0
Asset sales	0	0	0	0	61	1,606	0	0	0	0	0
Dividends paid	(48)	(227)	(151)	(138)	(195)	(387)	(316)	(48)	0	0	0
ESPP | options	5	12	10	15	3	2	0	0	0	0	0
Equity issuance, net	(204)	(229)	(10)	(11)	(8)	(154)	(101)	0	0	0	0
Debt issuance, net	(173)	1,313	1,329	551	921	(688)	(381)	(69)	(300)	(250)	(200)
Other	(64)	(6)	523	(86)	(165)	(131)	(99)	(138)	(28)	0	0
Chg in cash	222	(398)	(99)	43	(168)	(46)	444	213	(106)	(204)	(343)
FCF per share	2.72	1.46	(7.14)	(1.14)	(3.10)	(1.16)	5.53	1.93	0.91	0.19	(0.58)
Capex / revenue	0.39	0.46	0.95	0.47	0.59	0.50	0.14	0.35	0.09	0.10	0.22
Capex / depreciation	3.51	2.38	3.89	2.20	2.83	2.50	0.67	1.08	0.20	0.23	0.60

Source: Deutsche Bank

Figure 461: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	735	338	239	282	114	69	512	726	619	415	72
Accounts receivable	647	387	587	744	949	569	499	319	233	247	258
Other current assets	100	105	233	280	327	291	229	148	90	95	99
Total current assets	1,483	831	1,060	1,305	1,391	929	1,241	1,193	942	757	429
Net PP&E	6,634	10,048	11,897	13,026	14,558	12,113	11,484	10,062	9,627	9,250	9,077
Goodwill	0	0	0	0	0	0	0	0	0	0	0
Other assets	279	343	538	276	269	246	168	186	241	256	267
Total assets	8,397	11,221	13,495	14,608	16,218	13,287	12,892	11,440	10,810	10,263	9,773
Accounts payable	198	375	436	350	347	265	223	108	87	94	112
Accrued expenses	100	126	118	133	151	103	81	48	37	39	41
Current debt	0	80	0	0	0	0	300	300	249	199	167
Other current liabilities	136	140	273	429	554	301	259	177	266	282	294
Total current liabilities	434	720	827	911	1,052	669	864	633	640	615	614
Long-term debt	751	2,686	4,072	4,634	5,556	4,869	4,189	4,040	3,794	3,594	3,426
Other LT liabilities	424	527	498	574	560	462	417	299	501	519	532
Non-controlling int	0	125	691	765	727	722	723	709	696	696	696
Shareholders' equity	6,788	7,163	7,407	7,723	8,323	6,565	6,699	5,759	5,179	4,839	4,504
Total liabilities and equity	8,397	11,221	13,495	14,608	16,218	13,287	12,892	11,440	10,810	10,263	9,773
Total debt	751	2,767	4,072	4,634	5,556	4,869	4,489	4,340	4,043	3,793	3,593
Net debt	15	2,429	3,833	4,352	5,442	4,801	3,977	3,614	3,424	3,378	3,521
Debt/capital	10%	28%	35%	38%	40%	43%	40%	43%	44%	44%	44%
Debt/equity	11%	39%	55%	60%	67%	74%	67%	75%	78%	78%	80%
Debt turns	**0.3**	**1.9**	**3.6**	**3.0**	**2.8**	**2.4**	**2.7**	**4.8**	**8.2**	**9.3**	**10.7**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Oceaneering Int'l.

Reuters	Bloomberg
OII.N	OII US

David Havens
Research Analyst
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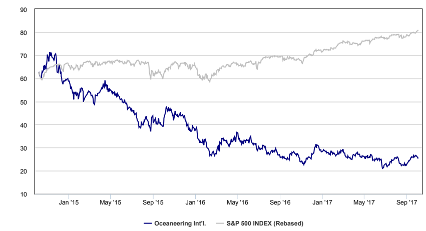
Price at 5 Oct 2017 (USD)	25.47
Price target	28.00
52-week range	31.53 - 21.03

Price/price relative



Performance (%)	1m	3m	12m
Absolute	10.7	9.8	-5.2
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	2,511.3
Shares outstanding (m)	98.6
Free float (%)	99
Volume (5 Oct 2017)	533,127
Option volume (und. shrs., 1M avg.)	27,711

Source: Deutsche Bank

Shifting Focus to Production Related Expenditures

Initiating coverage with a Hold rating and a $28 price target

Industry before company. While OII has a strong free cash flow track record and has maintained a flexible balance sheet, the deepwater industry is facing the most challenging environment in its history. Pricing remains elusive and volumes are set for a very slow grind higher as a deepwater spending recovery looks to be low calorie and elongated. While we believe OII has found an earnings bottom, the upside potential in 2018 is confined in our view by stubbornly low oil prices and stubbornly low deepwater spending activity.

OII has been among the top relative outperformers to-date

The resiliency of its business model despite the severity of the downturn has enabled the stock to be among the best relative outperformers year-to-date. OII has managed what it can control and has sustained strong relative free cash flows in the process. We believe OII is among the better positioned deepwater exposures, and for investors that are looking for downside protection, OII offers a more fiscally stable business model in the deepwater.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.30	-0.04A	0.00
2Q EPS	0.27	0.02A	0.04
3Q EPS	0.17	0.05	0.07
4Q EPS	0.03	-0.00	0.03
FY EPS (USD)	0.77	0.03	0.14
OLD FY EPS (USD)	0.77	–	–
% Change	0.0%	–	–
P/E (x)	38.7	–	184.1
DPS (USD)	0.96	0.60	0.60
Dividend Yield (%)	3.2	2.4	2.4
Revenue (USDm)	2,271.6	1,920.6	1,937.5

Source: Deutsche Bank estimates, company data

Valuation & Risks

Our $28 price target is 8.0x our estimate of the company's normalized EBITDA power of $380 million, which is in-line its five-year average 8.0x multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 12.0x our 2018 EBITDA estimate of $239 million.

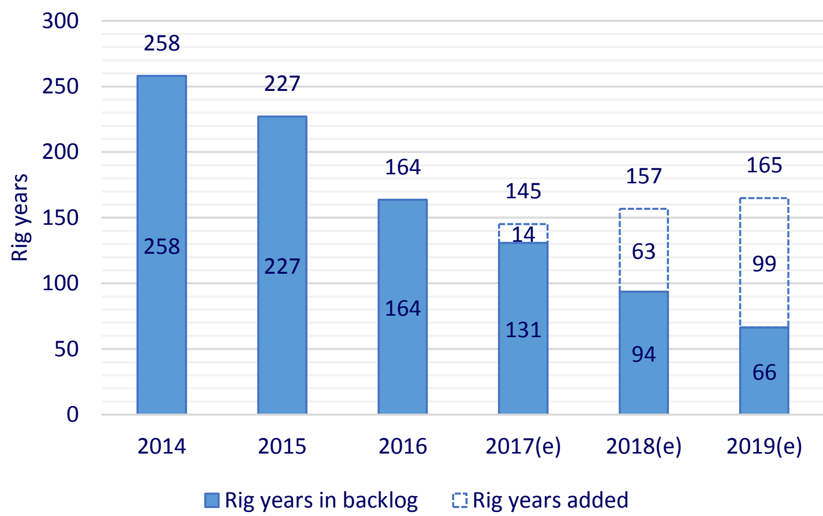
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) pricing tactics getting increasingly more aggressive for deepwater market share, and 4) another leg down in deepwater spending globally.

Key investment themes

Deepwater exposure creating earnings drag

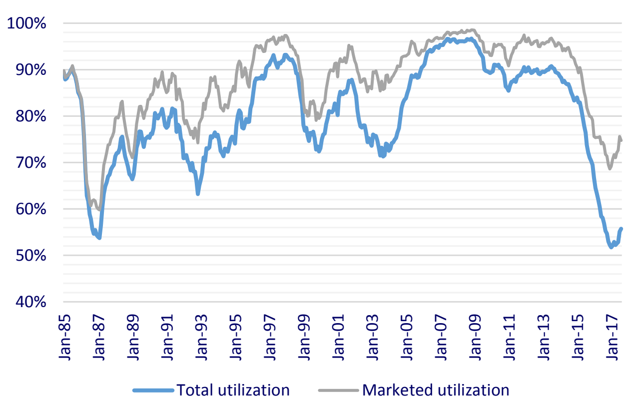
The days of winning as many newbuild deepwater rig contracts as possible are over and OII is pivoting its business mix away from drilling support to production services, or vessel-based activity. The current mix is 61% drilling support and 39% vessel-based activity. Its other businesses are generally tied to subsea installations and the cumulative growth in the installed base of subsea facilities. OII also benefits from maintenance, repair, and inspection work, which some operators have postponed during the downturn. Effectively, OII has exposure to all phases of the well lifecycle, but the macro is not cooperating as deepwater activity is poised to grind higher at a very laborious pace through 2019 in our view. ROV pricing remains challenging and has yet to hit an inflection point to where OII would have any leverage to increase price.

Figure 462: Deepwater drilling outlook (DBe)



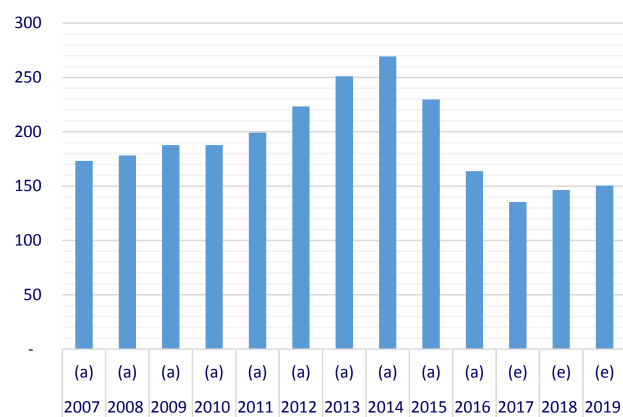
Source: ODS-Petrodata, Deutsche Bank

Figure 463: Floating rig utilization



Source: ODS-Petrodata

Figure 464: OII working ROV's



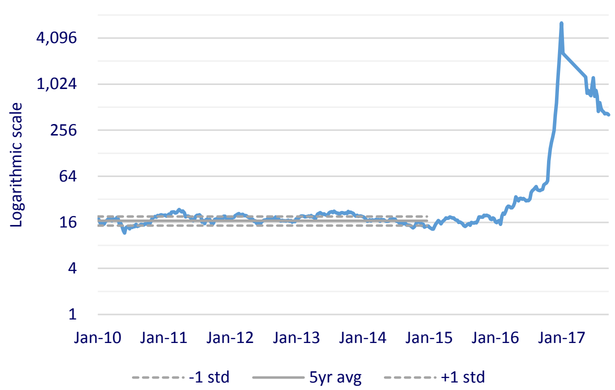
Source: Company reports, Deutsche Bank

Valuation and risks

Our $28 price target is 8.0x our estimate of the company's normalized EBITDA power of $380 million, which is in-line its five-year average 8.0x multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 12.0x our 2018 EBITDA estimate of $239 million.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) pricing tactics getting increasingly more aggressive for deepwater market share, and 4) another leg down in deepwater spending globally.

Figure 465: The P/E valuation band as blown out



Source: Factset

Figure 466: The 5yr P/E leading up to 2014

Source: Factset

Company description

Oceaneering International (OII) is a leading provider of products and services catering specifically to the offshore markets with a particular on the deepwater. The company has four reporting segments within its oilfield franchise including Remotely Operated Vehicles (ROVs), Subsea Products, Subsea Projects, and Asset Integrity. There is a fifth segment, Advanced Technologies, which operates outside of the oil patch and servicing the defense, aerospace and commercial theme park industries.

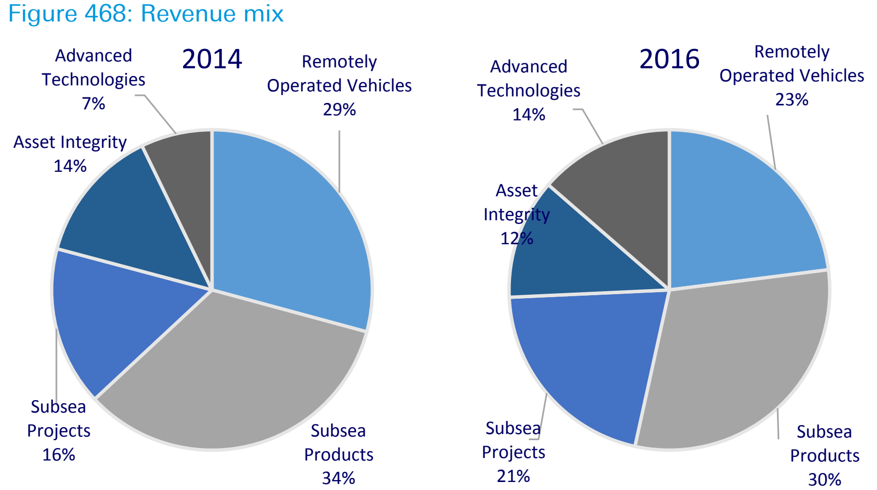
Figure 467: Reporting segments

Oceaneering	
Remotely Operated Vehicles - 6 added 2016, retired 41 - Fleet size 280 ('16), 315 ('15), 336 ('14) **Subsea Products** - Manufactured Products - Production control umbilicals - Subsea hardware - Service and Rental - Tooling and subsea work systems - IWOCS	**Subsea Projects** - Install/maint/inspection/repair - GOM, Angola, India - 5 DW vessels, 4 shallow water diving vessels **Asset Integrity** - Integrity management and testing services - Onshore and offshore; topside and subsea **Advanced Technologies** - Engineering services and manufacturing - US Dept of Defense, NASA, theme parks

Source: Company reports

OII's ROVs business has a fleet of 282 work-class vehicles and is the largest in the industry with about 28% market share. The Subsea Products segment manufactures umbilicals, production control equipment, and installation and workover control systems to name a few. The Subsea Projects segment does subsea intervention, installation, inspection, well tie-backs and ocean-bottom mapping services. Asset Integrity focuses on reducing unplanned maintenance and repair as well as ensuring safety at onshore and offshore facilities.

Figure 468: Revenue mix



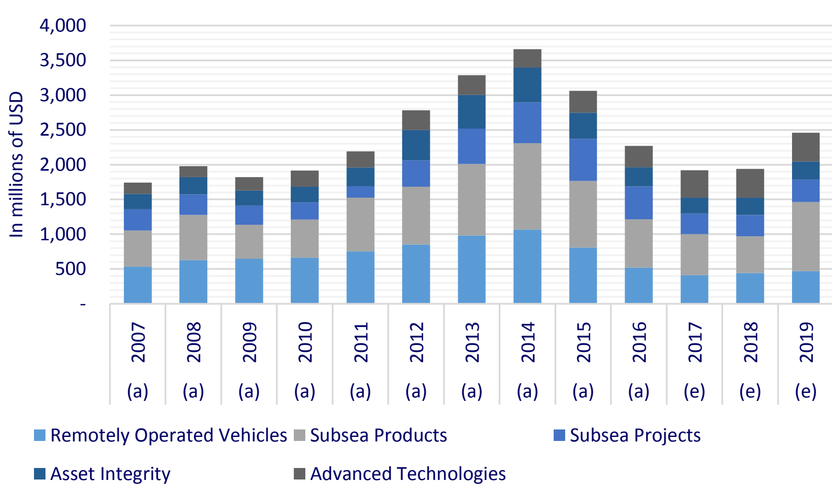
Source: Company reports, Deutsche Bank

Principal Sources and Uses of Cash Flow

Increasingly focused on production phase of offshore life cycle

OII remains committed to the deepwater and intends to continue investing in its core businesses while also expanding its deepwater capabilities in niche markets. But there is a change in strategy, which has the company focusing increasingly on production services and the operators' operating expenditures versus its capital expenditures. During the expansion period of the worldwide ultra-deepwater fleet, OII's core strategy was to win the business for as many ultra-deepwater newbuilds as possible because management viewed this as an annuity business given the rigs were receiving five-year term commitments. The company was not focused on vessel-based activity, but was intensely focused on this drilling support business. The company has since pivoted, and has also acquired privately held Blue Ocean Technologies, a provider of riser-less light well intervention services for the purpose of maximizing offshore production and recovery rates. The company also intends to grow geographically with its sights set on the Middle East, Mediterranean, and select opportunities in the Far East.

Figure 469: Revenue mix

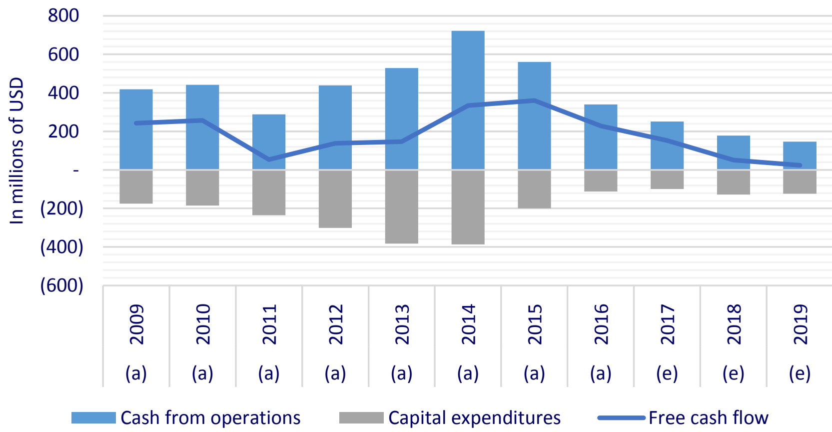


Source: Company reports, Deutsche Bank

Two-thirds of OII's ROVs are currently operating in a drilling support role where the company currently has a 53% market share. The other one-third are involved with vessel based activities, which include underwater pipeline inspection and surveys, maintenance and repair, installation and construction support, and subsea production facility operation and maintenance. Regionally, its international operations accounted for 57% of total revenue in 2016, flat from 2015 levels. Its international operations are focused mainly in the North Sea, Africa, Brazil, Australia, and Asia.

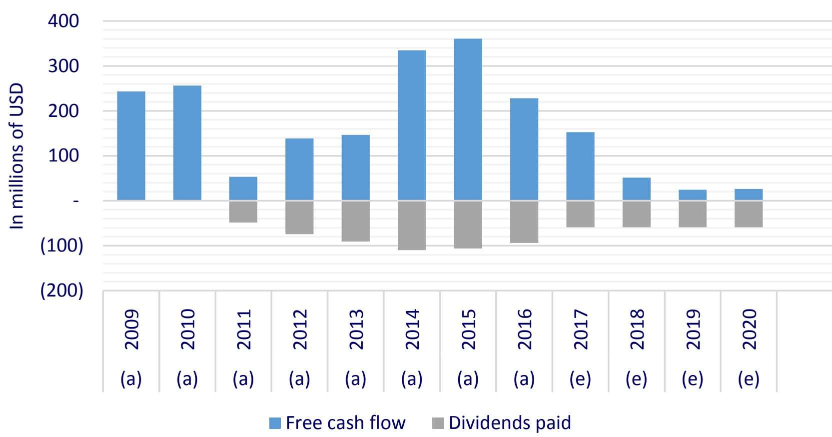
A significant portion of total revenues comes from Subsea Projects segment in the US Gulf of Mexico, which experiences some seasonality with heightened activity in the second and third quarters.

Figure 470: Strong free cash flow track record



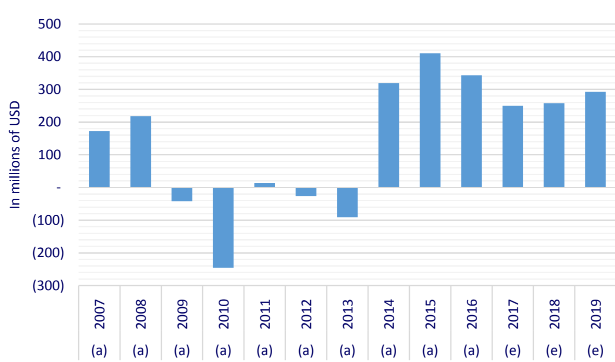
Source: Company reports, Deutsche Bank

Figure 471: Dividends cut in 2016



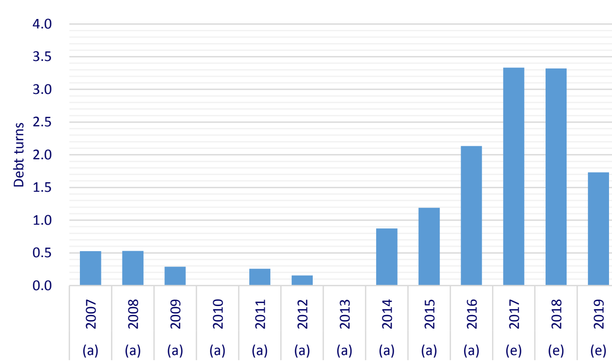
Source: Company reports, Deutsche Bank

Figure 472: Net debt



Source: Deutsche Bank

Figure 473: Debt turns



Source: Deutsche Bank

Figure 474: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Remotely Operated Vehicles	649	662	755	854	982	1,069	808	522	410	444	471
Subsea Products	488	549	770	829	1,028	1,239	960	692	594	527	992
Subsea Projects	275	248	167	380	509	589	604	473	293	307	323
Asset Integrity	216	223	267	435	482	500	373	275	230	247	259
Advanced Technologies	194	235	233	285	286	263	318	309	395	412	412
Total revenue	1,822	1,917	2,193	2,783	3,287	3,660	3,063	2,272	1,921	1,938	2,457
Segment gross margin:											
Remotely Operated Vehicles	237	248	260	290	328	361	249	100	64	83	88
Subsea Products	115	161	207	241	311	365	284	152	88	70	154
Subsea Projects	85	61	24	81	109	124	117	54	24	33	53
Inspection	41	42	46	71	82	87	51	45	44	56	76
Advanced Technologies	25	33	34	39	45	32	30	34	52	57	57
Unallocated expenses	(65)	(73)	(81)	(94)	(109)	(111)	(72)	(44)	(65)	(66)	(66)
Total gross margin	438	472	489	628	766	859	659	340	206	232	361
D&A	123	148	151	176	202	230	241	236	210	195	182
EBIT											
Remotely Operated Vehicles	208	208	225	249	282	321	214	66	38	49	52
Subsea Products	61	109	142	171	231	281	202	88	40	32	71
Subsea Projects	75	52	14	63	94	108	94	37	9	15	24
Inspection	26	26	31	45	55	55	22	14	15	21	28
Advanced Technologies	12	17	17	21	25	13	10	12	28	31	31
Unallocated expenses	(90)	(100)	(112)	(121)	(142)	(150)	(114)	(82)	(103)	(104)	(104)
EBIT	292	311	317	429	545	628	428	135	28	44	103
Interest (expense)	(8)	(3)	(1)	(4)	(2)	(5)	(25)	(25)	(29)	(30)	(29)
Interest income	1	1	1	2	1	0	1	4	8	10	9
Equity income	3	2	4	2	0	(0)	2	0	(2)	(2)	(2)
Other income	2	(3)	(1)	(6)	(1)	(0)	(0)	0	(1)	(0)	(0)
PBT	290	308	320	422	542	623	405	114	4	22	81
Income tax (expense)	(101)	(106)	(101)	(133)	(171)	(195)	(128)	(39)	(1)	(8)	(30)
Non-controlling interest	-	-	-	-	-	-	-	-	-	-	-
Preferred dividends	-	-	-	-	-	-	-	-	-	-	-
Net income (operating)	188	202	219	289	372	428	277	75	2	14	51
Discontinued ops	-	-	-	-	-	-	-	-	-	-	-
Unusual after-tax	-	(2)	17	-	-	-	(46)	(51)	(4)	-	-
Net income (GAAP)	**188**	**200**	**236**	**289**	**372**	**428**	**231**	**25**	**(1)**	**14**	**51**
Reconciliation for NCI	(1)	-	-	-	-	-	-	-	-	-	-
Operating EPS	**1.70**	**1.85**	**2.01**	**2.66**	**3.42**	**4.00**	**2.80**	**0.77**	**0.03**	**0.14**	**0.52**
GAAP EPS	1.70	1.83	2.16	2.66	3.42	4.00	2.34	0.25	(0.01)	0.14	0.52
DPS	0.00	0.00	0.45	0.69	0.84	1.03	1.08	0.96	0.60	0.60	0.60
Diluted shares	110	110	109	109	109	107	99	98	99	99	99
EBITDA margin	22.8%	24.0%	21.3%	21.7%	22.7%	23.4%	21.8%	16.3%	12.4%	12.3%	11.6%
EBIT margin	16.0%	16.2%	14.4%	15.4%	16.6%	17.2%	14.0%	5.9%	1.5%	2.3%	4.2%
Tax rate	35.0%	34.3%	31.5%	31.5%	31.5%	31.3%	31.7%	34.1%	35.9%	37.0%	37.0%
EBIT margin											
Remotely Operated Vehicles	32.0%	31.4%	29.8%	29.2%	28.7%	30.0%	26.5%	12.6%	9.2%	11.0%	11.0%
Subsea Products	12.4%	19.8%	18.5%	20.6%	22.5%	22.7%	21.1%	12.7%	6.8%	6.1%	7.2%
Subsea Projects	27.5%	21.1%	8.6%	16.7%	18.4%	18.3%	15.5%	7.8%	3.2%	5.0%	7.6%
Inspection	12.2%	11.6%	11.5%	10.4%	11.5%	11.1%	5.9%	5.1%	6.7%	8.5%	11.0%
Advanced Technologies	6.4%	7.2%	7.1%	7.4%	8.7%	5.0%	3.1%	4.0%	7.1%	7.4%	7.4%

Source: Deutsche Bank

Figure 475: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	188	202	219	289	372	428	277	75	2	14	51
Depreciation	123	148	151	176	202	230	241	236	210	195	182
Deferred tax	22	31	8	21	52	71	29	0	(24)	-	-
Chg in receivables	12	12	(100)	(94)	(102)	(8)	179	123	87	(48)	(146)
Chg in inventories	14	(22)	(11)	(76)	(111)	66	59	18	54	(33)	(96)
Chg in payables	(6)	(1)	9	87	128	(44)	(45)	(117)	(8)	10	29
Other	66	71	13	36	(13)	(21)	(180)	5	(70)	42	127
Cash from operations	418	442	289	439	529	722	560	341	252	179	147
Capital expenditures	(175)	(185)	(235)	(301)	(383)	(387)	(200)	(112)	(99)	(127)	(123)
Free cash flow	243	257	54	138	146	335	360	228	152	52	24
Acquisitions	-	(22)	(292)	(9)	(11)	(40)	(224)	(30)	-	-	-
Asset sales	13	15	44	4	12	2	0	6	1	-	-
Dividends paid	-	-	(49)	(75)	(91)	(110)	(106)	(94)	(59)	(59)	(59)
ESPP | options	-	-	-	-	-	-	-	-	-	-	-
Equity issuance, net	2	(49)	(17)	(17)	-	(590)	(100)	-	-	-	-
Debt issuance, net	(109)	(120)	120	(27)	(94)	742	50	-	-	-	(300)
Other	3	2	1	(0)	9	0	(25)	(45)	(0)	-	-
Chg in cash	151	83	(139)	14	(29)	339	(45)	65	94	(8)	(335)

Source: Deutsche Bank

Figure 476: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	162	245	106	121	91	431	385	450	544	536	201
Accounts receivable	435	424	550	667	769	778	613	490	403	451	597
Inventories	232	237	255	331	442	376	328	280	226	259	355
Other current assets	44	78	73	84	131	129	191	43	40	45	60
Total current assets	874	984	984	1,203	1,433	1,714	1,517	1,263	1,213	1,292	1,214
Net PP&E	766	786	893	1,025	1,189	1,306	1,267	1,153	1,055	987	928
Goodwill	131	143	333	363	344	331	427	444	451	451	451
Other assets	109	117	190	177	162	161	218	271	244	273	361
Total assets	1,880	2,031	2,401	2,768	3,129	3,512	3,430	3,130	2,962	3,002	2,953
Accounts payable	86	86	111	130	130	124	118	78	69	79	109
Current debt	-	-	-	-	-	-	-	-	-	300	-
Other current liabilities	302	354	390	487	597	555	498	431	350	392	519
Total current liabilities	389	440	501	617	727	679	616	508	420	772	628
Long-term debt	120	-	120	94	-	750	796	793	794	494	494
Other LT liabilities	147	200	221	241	358	425	439	312	283	316	419
Shareholders' equity	1,224	1,390	1,558	1,815	2,043	1,658	1,579	1,517	1,466	1,420	1,412
Total liabilities and equity	1,880	2,031	2,401	2,768	3,129	3,512	3,430	3,130	2,962	3,002	2,953
Total debt	120	-	120	94	-	750	796	793	794	794	494
Net debt	(42)	(245)	14	(27)	(91)	319	411	343	250	258	293
Debt/capital	9%	0%	7%	5%	0%	31%	34%	34%	35%	36%	26%
Debt/equity	10%	0%	8%	5%	0%	45%	50%	52%	54%	56%	35%
Debt turns	**0.3**	**0.0**	**0.3**	**0.2**	**0.0**	**0.9**	**1.2**	**2.1**	**3.3**	**3.3**	**1.7**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Oil States

Reuters	Bloomberg
OIS.N	OIS US

Jason Bandel
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Price at 5 Oct 2017 (USD)	25.55
Price target	26.00
52-week range	41.20 - 21.00

Leaning on onshore recovery

Maintaining our Hold rating and $26 price target

We are maintaining our Hold rating on Oil States and our price target of $26. Despite its size, we believe OIS has a proprietary technology product offering that allows for high market share levels, but the downturn in offshore activity and spending has weighed on the overall earnings power of the company. While its Offshore/ Manufactured Products segment backlog is finally approaching a trough, the visibility around FIDs moving forward and spending shaking loose offshore remains challenging. Its Well Site Services segment continues to see improved utilization driven by increases in complex completion directed activity and helping to partially offset the lower Offshore revenues.

Later cycle play on offshore development

We view OIS as a later cycle play on when activity and spending starts to come back towards offshore development. As operators pushed further into deepwater and production is brought online, more production facilities are needed as fields are developed further from existing infrastructure. The push for standardization and tie-back opportunities utilizing existing infrastructure has caused its backlog to lean more towards smaller, short-cycle orders and non-energy applications as project work has shrunk.

Focus on what they can control

OIS management has done a good job on focusing on the onshore recovery to help partially offset the downturn in offshore spending, both through its shorter-cycle products and its Well Site Service segment. OIS has also resumed buying back stock this year and has $120.5mm remaining authorization.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.24	-0.34A	-0.14
2Q EPS	-0.22	-0.27A	-0.08
3Q EPS	-0.19	-0.21	-0.02
4Q EPS	-0.20	-0.18	0.01
FY EPS (USD)	-0.86	-0.99	-0.23
OLD FY EPS (USD)	-0.86	-1.00	-0.20
% Change	-0.3%	-0.7%	12.3%
P/E (x)	–	–	–
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	694.4	669.8	791.4

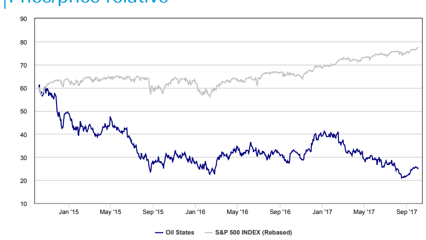
Source: Deutsche Bank estimates, company data

Key changes

EPS (USD)	-1.00 to -0.99	↑	-0.7%
Revenue (USDm)	680.5 to 669.8	↓	-1.6%

Source: Deutsche Bank

Price/price relative



Performance (%)	1m	3m	12m
Absolute	15.5	-10.7	-20.7
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,284.6
Shares outstanding (m)	50.3
Free float (%)	154
Volume (5 Oct 2017)	126,256
Option volume (und. shrs., 1M avg.)	25,405

Source: Deutsche Bank

Valuation & Risks

We are continuing coverage of OIS with a $26 price target. This is 5.7x our estimate of the company's normalized EBITDA of $250mm, which is a 0.5 turn discount to the 6.2x five-year average multiple leading up to the 2014 collapse in oil prices. The main investment risks include: 1) operator spending continues to shift towards onshore opportunities causing further delays towards offshore development, 2) increasing focus on standardization and workflow design may cause additional dollars to come out of the deepwater cost structure, 3) negative revisions to global oil demand, and 4) an upside risk is OIS could potentially be an acquisition target with its low leverage and portfolio of high technology offerings.

Key investment themes

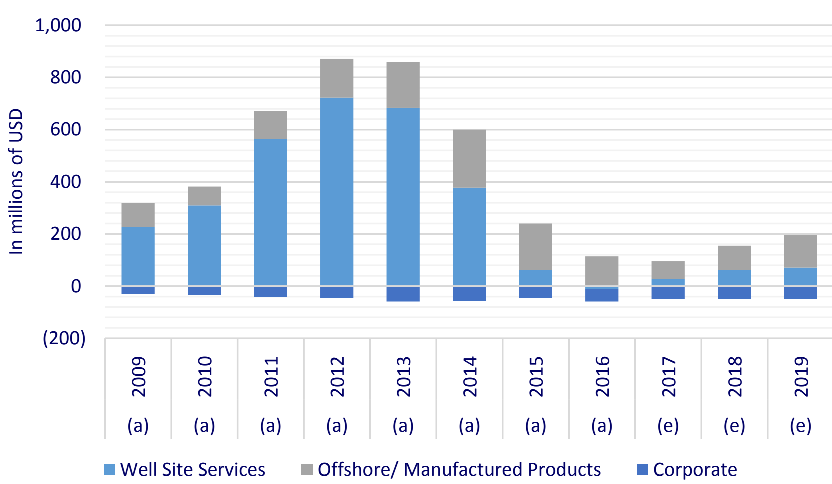
Later cycle play on offshore infrastructure development

While overall sentiment towards deepwater development remains poor, we continue to believe that long term development of deepwater reserves are not going away. OIS is a later cycle play on offshore infrastructure development as operators pushed further into deepwater which required more production facilities to be built as fields are developed further from existing infrastructure. The downturn in deepwater activity levels have driven operators to focus on shorter-cycle onshore projects and maximizing existing infrastructure offshore. This has led to a push for standardization and leveraging tie-back opportunities reducing the need in the near term for new production facilities. FIDs are starting to shake loose and we look for additional projects to be announced as we move closer to 2018. Another potential headwind comes from Brazil which accounts for 25-30% of the FPSO market.

Cash flow profile changed post accommodations spin-off and downturn

During the 2009-2014 upcycle, OIS' Well Site Services segment accounted for 58% of EBITDA. Following the spin-off of its accommodations business and the downturn weighing on onshore completion activity, Offshore Products started to be the primary contributor to EBITDA and cash flow generation. Its backlog does provide for some visibility for revenues and cash flow, but OIS' product lines tend to have shorter lead times than other manufacturers in the oilfield services universe. As such the company recognizes 90% of its backlog as revenue in a given year. OIS did manage to stay free cash flow positive during the downturn.

Figure 477: Offshore Products main EBITDA contributor during downturn



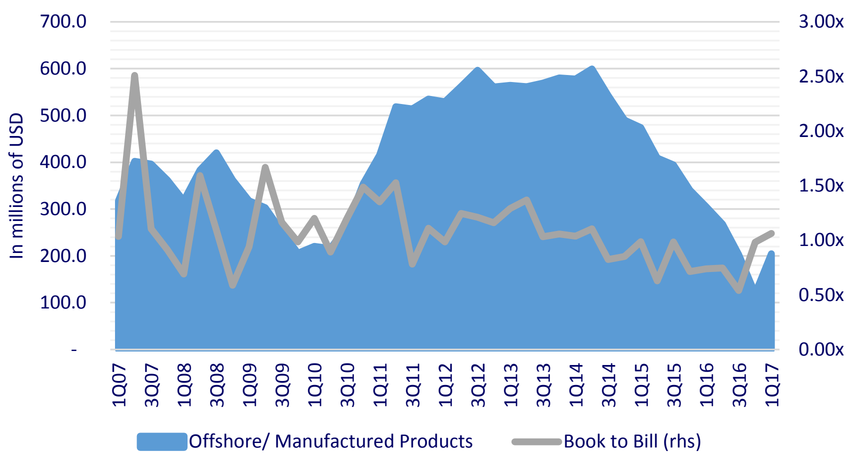
Source: Company reports, Deutsche Bank

Changing backlog composition - increasing leverage to shorter cycle products

OIS backlog levels have been falling due to delays in project awards during the downturn and with incremental dollars going towards North American onshore. Also this environment has led to smaller sized orders being booked into backlog. This onshore focused recovery has actually led to increasing leverage to shorter cycle products (including elastomer consumables and valve products), which has helped to increase its book to bill ratio and move the company closer to a trough in its backlog levels. These shorter cycle products now makeup close to 40% of total Offshore Products revenue, as compared to its historical range of 15-20%.

These bookings also increase OIS' overall exposure to onshore markets, at least until FIDs start to shake loose and project work starts to increase.

Figure 478: Backlog levels have been falling, but book to bill has started to turn

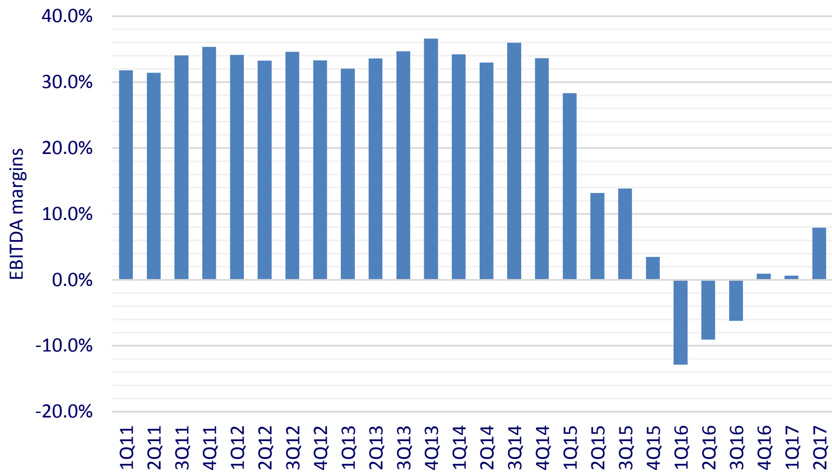


Source: Company reports, Deutsche Bank

Increasing onshore exposure changes margin profile

The downturn in offshore activity and spending has increased OIS' onshore exposure. In the 1H17, US shale play activity accounted for almost 50% of consolidated revenues. Also as we just discussed, the increase in shorter cycle consumables (elastomers, valves) in its Offshore/ Manufactured Products segment is also raising their onshore exposure. While its Completion Services product line inside its Well Site Services segment also has some exposure to Gulf of Mexico and International markets, it is mainly US shale focused (77% of 2Q17 Completion Services revenue). This is currently weighing on margins for the company as its Completion Services margins continue to recover from the downturn and remain below historical levels.

Figure 479: Increasing onshore exposure hurting overall margins as Completion Services margins still recovering



Source: Company reports, Deutsche Bank

Proprietary technology product offering despite its size

Despite its size, OIS has a proprietary technology product offering allowing for high market share levels and generally solid through-cycle margins. OIS' Well Site Services segment is benefiting from the rising well complexity and service intensity in the US. Its Offshore/ Manufactured Products segment has high proprietary content around its connector systems, such as its FlexJoint and Merlin Connectors. This level of proprietary content is generally rare for smaller oilfield services companies. While Spears & Associates data shows OIS holds around a mid-single digit market share level in the broadly defined Rig Equipment space, in some of its proprietary products their market share can be in the 90% range.

Valuation and risks

We are continuing coverage of Oil States and maintaining our $26 price target. This is 5.7x our estimate of the company's normalized EBITDA of $250mm, which is a 0.5 turn discount to the 6.2x five-year average multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 12.4x our 2018 EBITDA estimate of $106mm and 9x our 2019 EBITDA estimate of $146mm. We expect valuations will continue to consolidate until the path towards a deepwater activity recovery becomes clearer.

The main investment risks include: 1) operator spending continues to shift towards onshore opportunities causing further delays towards offshore development, 2) increasing focus on standardization and workflow design may cause additional dollars to come out of the deepwater cost structure, 3) negative revisions to global oil demand, 4) an upside risk is OIS could potentially be an acquisition target with its low leverage and portfolio of high technology offerings.

Company description

Oil States International (OIS) is a mid-cap specialty products manufacturer and oilfield services provider focused on delivering technology and solutions to the deepwater capital equipment market around the world and the North America shale play market. Following its spin-off of its accommodations segment, OIS is a more focused company leveraged to the deepwater production infrastructure buildout offshore and rising service intensity and complexity onshore.

Its Offshore Products segment is driven by infrastructure development, rig refurbishments and upgrades, and rig newbuild supply growth. Its Well Site Services segment is driven by completion directed spending and activity levels in the US. OIS also has a fleet of 34 land drilling rigs mostly based in the Permian and the Rockies, that in good times generates positive cash flow that OIS invests in other parts of the business.

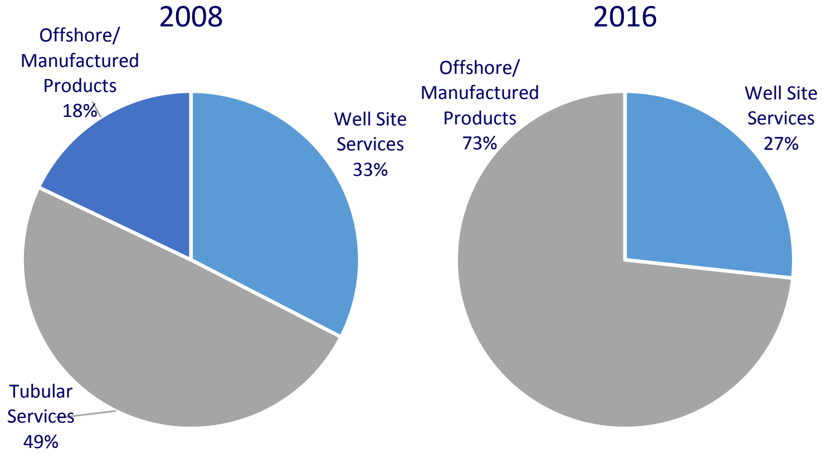
Figure 480: Company reporting segments

Oil States	
Offshore/ Manufactured Products	**Well Site Services**
- Flexible bearings, adanced connector systems	- Completion Services
- FlexJoints, Merlin Connectors	- Wellhead isolation
- Casing and conductor connections	- Wireline and coiled tubing support
- Riser systems	- Frac valve and flowback services
- Subsea pipeline products	- Ball launching services
- Valves, manifolds	- Drilling Services (Capstar - 34 rigs)
- Cranes, winches, morring systems	
- BOP assembly and testing	

Source: Company reports, Deutsche Bank

In its Offshore segment, OIS' FlexJoints and Merlin Connectors have the high proprietary content. Short cycle manufactured products include elastomers and valves that tend to have some land-based exposure. Short-cycle products have moved from 15-20% of total Offshore Product revenue to 36% in 1Q17, due to the slow-down in project work from FIDs.

Figure 481: Revenue by reporting segment

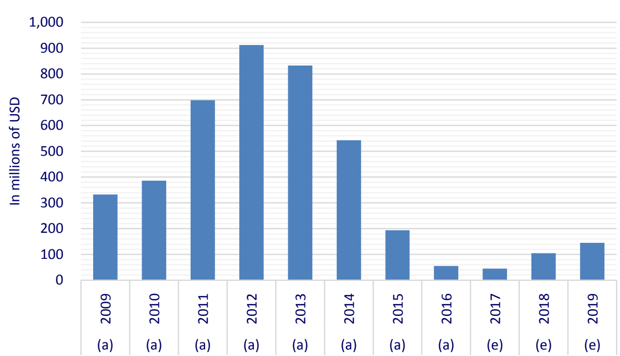


Source: Company reports, Deutsche Bank

Principal Sources and Uses of Cash Flow

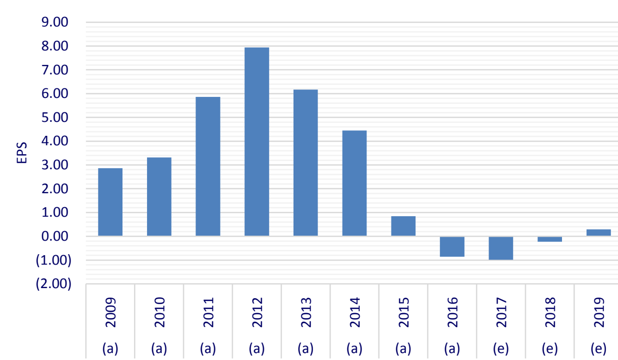
In this current recovery coming out of the downturn, OIS' Offshore/ Manufactured Products segment has been the primary contributor to EBITDA, while its Well Site Services segment is just starting to contribute positive EBITDA as utilization levels improve. Its backlog does provide for some visibility in cash flows, but its product lines tend to have shorter lead times than other manufacturers in the oilfield services universe. As such the company recognizes 90% of its backlog as revenue in a given year. The primary uses of cash have generally been on capex to purchase rentals for its completion services business and an expansion campaign to build out manufacturing facilities both in the US and construct a new facility in Edinburgh (while retiring the old one in Aberdeen). OIS also is slowly building out facilities in Brazil. Post accommodations spin-off, OIS has used cash to pay down debt (see more details in next section). Lastly, OIS also has a history of stock repurchases and has resumed buying back stock this year and has $120.5mm remaining authorization.

Figure 482: Consolidated EBITDA



Source: Company reports, Deutsche Bank

Figure 483: Earnings per share

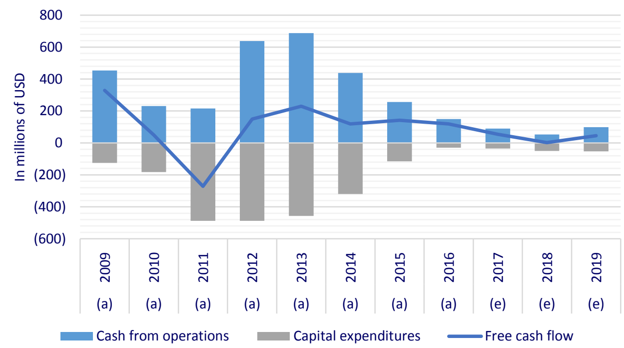


Source: Company reports, Deutsche Bank

Balance Sheet and FCF

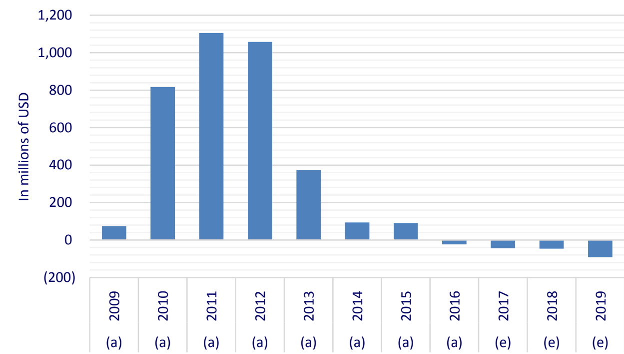
Following the spin-off of its accommodations segment, OIS was able to de-lever its already strong balance sheet and continued to pay down debt during the downturn. This leaves the company well positioned to pursue growth opportunities or bolt-on acquisitions as their history has shown. At the end of Q1, OIS has a $600mm revolver that matures in 2019 with $22.4mm outstanding. The revolver does have an option to increase its capacity to $750mm.

Figure 484: Free cash flow and capex



Source: Company reports, Deutsche Bank

Figure 485: Net debt



Source: Company reports, Deutsche Bank

Figure 486: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Well Site Services	787	1,014	1,519	1,828	1,794	1,111	376	186	291	350	356
Completion Services	234	343	488	523	578	657	308	163	243	296	300
Drilling Services	71	133	166	192	170	201	68	23	48	54	56
Offshore/ Manufactured Pr	509	429	586	804	883	962	724	509	379	442	536
Accomodations	481	538	865	1,113	1,046	253	0	0	0	0	0
Tubular Services	812	969	1,375	1,782	799	0	0	0	0	0	0
Total revenues	2,108	2,412	3,479	4,414	3,476	2,072	1,100	694	670	791	892
Segment EBITDA:											
Well Site Services	226	310	564	723	684	378	63	(11)	27	62	71
Offshore/ Manufactured Pr	92	72	107	149	175	222	177	114	68	93	124
Corporate	(30)	(33)	(41)	(46)	(59)	(57)	(46)	(47)	(50)	(50)	(50)
Total EBITDA	333	386	698	913	832	543	194	56	45	105	145
Segment D&A:											
Well Site Services	105	111	172	212	258	141	103	93	85	92	94
Offshore/ Manufactured Pr	11	11	13	15	18	22	27	24	26	26	26
Corporate	1	1	1	1	1	1	1	1	1	1	1
EBIT	213	262	508	673	551	376	61	(66)	(66)	(13)	25
Interest (expense)	(15)	(15)	(58)	(69)	(76)	(26)	(6)	(5)	(5)	(5)	(5)
Interest income	0	1	2	2	2	1	1	0	0	0	0
Equity income	1	0	(0)	0	(0)	0	0	0	0	0	0
Other income	0	0	4	8	4	3	1	1	1	1	1
PBT	200	248	455	614	481	354	57	(70)	(70)	(17)	21
Income tax (expense)	(56)	(73)	(132)	(173)	(136)	(118)	(14)	27	20	5	(7)
Non-controlling interest	(0)	(1)	(1)	(1)	(1)	(0)	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	144	175	322	440	343	236	43	(43)	(50)	(11)	14
Discontinued ops	0	0	0	0	88	15	0	(0)	0	0	0
Unusual after-tax	(84)	(7)	0	9	(10)	(72)	(14)	(3)	(1)	0	0
Net income (GAAP)	**59**	**168**	**322**	**449**	**421**	**179**	**29**	**(46)**	**(51)**	**(11)**	**14**
Operating EPS	**2.87**	**3.31**	**5.86**	**7.94**	**6.17**	**4.45**	**0.85**	**(0.86)**	**(0.99)**	**(0.23)**	**0.29**
GAAP EPS	1.18	3.19	5.86	8.10	7.57	3.37	0.57	(0.92)	(1.01)	(0.23)	0.29
DPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Diluted shares	50	53	55	55	56	53	50	50	50	50	50
EBITDA margin	15.7%	16.0%	20.0%	20.5%	23.8%	26.1%	17.2%	7.6%	6.8%	13.4%	16.4%
EBIT margin	10.1%	10.9%	14.6%	15.3%	15.8%	18.1%	5.6%	-9.5%	-9.8%	-1.6%	2.8%
Tax rate	28.1%	29.3%	28.9%	28.2%	28.3%	33.3%	25.2%	38.7%	28.4%	32.0%	32.0%
EBITDA margin											
Well Site Services	28.7%	30.5%	37.2%	39.5%	38.1%	34.0%	16.7%	(6.0%)	9.3%	17.8%	19.9%
Offshore/ Manufactured Pr	18.1%	16.8%	18.3%	18.6%	19.8%	23.1%	24.5%	22.4%	18.0%	21.0%	23.1%

Source: Deutsche Bank

Figure 487: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	144	175	322	440	343	236	43	(43)	(50)	(11)	14
Depreciation	118	124	188	230	278	164	128	119	111	119	121
Deferred tax	(15)	21	27	17	(8)	(12)	(3)	(38)	(15)	0	0
Chg in receivables	206	(62)	(260)	(83)	48	(66)	157	86	24	(44)	(26)
Chg in inventories	201	(75)	(154)	(34)	26	1	18	32	18	(26)	(18)
Chg in payables	(169)	82	48	31	(11)	6	(98)	(28)	(5)	6	4
Other	(31)	(33)	45	37	12	108	12	21	5	8	3
Cash from operations	453	231	216	637	687	438	256	149	90	53	98
Capital expenditures	(124)	(182)	(487)	(488)	(458)	(319)	(115)	(30)	(35)	(51)	(52)
Free cash flow	329	49	(272)	150	230	119	141	120	54	2	46
Acquisitions	0	(710)	(2)	(80)	(44)	0	(33)	0	(13)	0	0
Asset sales	3	3	6	15	610	4	3	2	1	0	0
Dividends paid	0	0	0	0	0	0	0	0	0	0	0
ESPP	options	0	0	0	0	16	10	6	0	0	0	0
Equity issuance, net	3	23	2	(2)	(113)	(232)	(113)	(4)	(21)	0	0
Debt issuance, net	(300)	648	266	126	(341)	(160)	(18)	(81)	5	0	0
Other	24	(6)	(24)	(27)	(12)	(286)	(3)	(3)	1	0	0
Chg in cash	60	7	(25)	181	346	(546)	(17)	33	26	2	46
FCF per share	6.56	0.92	(4.94)	2.70	4.13	2.23	2.81	2.38	1.08	0.04	0.91
Capex / revenue	0.06	0.08	0.14	0.11	0.13	0.15	0.10	0.04	0.05	0.06	0.06
Capex / depreciation	1.05	1.47	2.59	2.12	1.65	1.94	0.90	0.25	0.32	0.42	0.43

Source: Deutsche Bank

Figure 488: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	4	9	7	14	9	10	65	132	201	412	622
Accounts receivable	131	294	461	388	437	635	232	169	347	369	373
Inventories	56	64	100	141	127	156	128	108	113	123	125
Other current assets	29	32	57	25	32	52	66	70	20	22	22
Total current assets	219	399	627	568	605	852	492	479	681	926	1,142
Net PP&E	750	1,253	1,557	1,852	1,903	650	639	553	489	515	403
Investment in affiliates	5	6	0	0	0	0	0	0	0	0	0
Goodwill	219	475	467	521	514	252	264	263	269	269	269
Other assets	33	182	189	241	189	81	85	77	91	34	11
Total assets	1,932	3,016	3,704	4,440	4,131	1,810	1,599	1,384	1,327	1,362	1,313
Accounts payable	209	305	349	280	149	109	59	34	33	39	43
Income taxes	14	5	10	30	33	9	8	6	3	1	0
Current debt	0	181	34	30	1	1	1	1	1	1	1
Deferred revenue	87	61	75	66	50	49	37	21	21	8	2
Other current liabilities	4	3	6	112	141	104	50	45	42	16	5
Total current liabilities	315	554	475	519	374	271	154	107	99	65	52
Long-term debt	164	732	1,143	1,280	973	147	126	45	50	50	50
Deferred taxes	55	81	97	129	123	34	40	5	4	4	4
Other LT liabilities	16	20	26	47	37	17	20	22	23	9	3
Shareholders' equity	1,382	1,629	1,963	2,466	2,625	1,341	1,258	1,204	1,151	1,228	1,191
Total liabilities and equity	1,932	3,016	3,704	4,440	4,131	1,810	1,599	1,384	1,327	1,362	1,313
Total debt	165	913	1,177	1,310	973	147	126	46	51	51	51
Net debt	75	817	1,105	1,057	374	94	90	(23)	(44)	(46)	(92)
Debt/capital	11%	36%	37%	35%	27%	10%	9%	4%	4%	4%	4%
Debt/equity	12%	56%	60%	53%	37%	11%	10%	4%	4%	4%	4%
Debt turns	**0.5**	**2.4**	**1.7**	**1.5**	**1.2**	**0.3**	**0.7**	**0.9**	**1.1**	**0.5**	**0.3**
Cash conversion	1.36	0.60	0.31	0.70	0.83	0.81	1.32	2.69	1.98	0.50	0.68
Cash from operations	453	231	216	637	687	438	256	149	90	53	98
Capital expenditures	124	182	487	488	458	319	115	30	35	51	52
Free cash flow	329	49	(272)	150	230	119	141	120	54	2	46
Dividends paid	0	0	0	0	0	0	0	0	0	0	0
Dividends per share	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Patterson-UTI

Reuters	Bloomberg
PTEN.OQ	PTEN US

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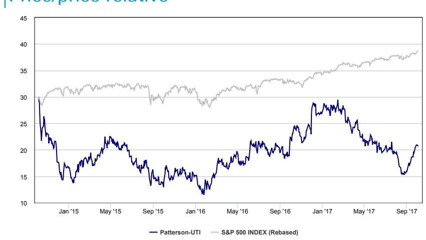
Price at 5 Oct 2017 (USD)	21.30
Price target	25.00
52-week range	29.47 - 15.26

Price/price relative



Performance (%)	1m	3m	12m
Absolute	30.6	-0.3	-3.8
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	4,066.6
Shares outstanding (m)	190.9
Free float (%)	100
Volume (5 Oct 2017)	823,423
Option volume (und. shrs., 1M avg.)	91,316

Source: Deutsche Bank

Evolving with the times

Initiating coverage with a Buy rating and a $25 price target

PTEN's increased frac exposure provides line of sight to restoring its EBITDA to 2014 levels that most of its peers do not have. While we believe oil prices will be confined to a range of $45 – 55, and the US rig count will grow by a mere 6% in 2018, scarcity value in frac is being recreated much faster than in land rigs. While we do not expect pricing in frac to move up unabated throughout 2018, PTEN's frac increased exposure provides it with peer leading EBITDA growth in an otherwise challenging cycle with challenging returns.

Frac business to drive pivot in earnings with $0.4 billion of EBITDA in 2018

The oilfield is not offering up the same margins and returns it did over the prior two cycles. So for those companies that have been caught flat footed, the earnings deterioration has been devastating. While the returns are materially lower, PTEN has at least repositioned the organization to rebuild its EBITDA. It is the second largest provider of super-spec rigs in the US with 23% market share and it is now the fifth largest US frac company. These are two businesses that are getting utilization and pricing, albeit more so for frac.

Clean balance sheet offers fiscal stability

We expect PTEN to exit the year with a debt turn of 1.6x, down from the 2.8x in 2Q17. This compares very favorably to some of its drilling and services peers that are in the 5-8x range.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.59	-0.42A	-0.08
2Q EPS	-0.61	-0.21A	-0.07
3Q EPS	-0.58	-0.19	-0.03
4Q EPS	-0.53	-0.13	0.00
FY EPS (USD)	-2.32	-0.91	-0.17
OLD FY EPS (USD)	-2.18	–	–
% Change	6.4%	–	–
P/E (x)	–	–	–
DPS (USD)	0.16	0.08	0.08
Dividend Yield (%)	0.8	0.4	0.4
Revenue (USDm)	893.0	2,321.0	3,107.9

Source: Deutsche Bank estimates, company data

Valuation

Our $25 price target is 5.0x our estimate of the company's normalized EBITDA of $1.1 billion, which is a half turn premium to its 4.3x five-year average multiple leading up to the 2014 collapse in oil prices. We assign the half-turn premium because of the peer leading earnings leverage it has in an otherwise challenging cycle.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a rapid increase in frac newbuilds, and 4) a rapid acquisition strategy that threatens the returns of the company.

Key investment themes

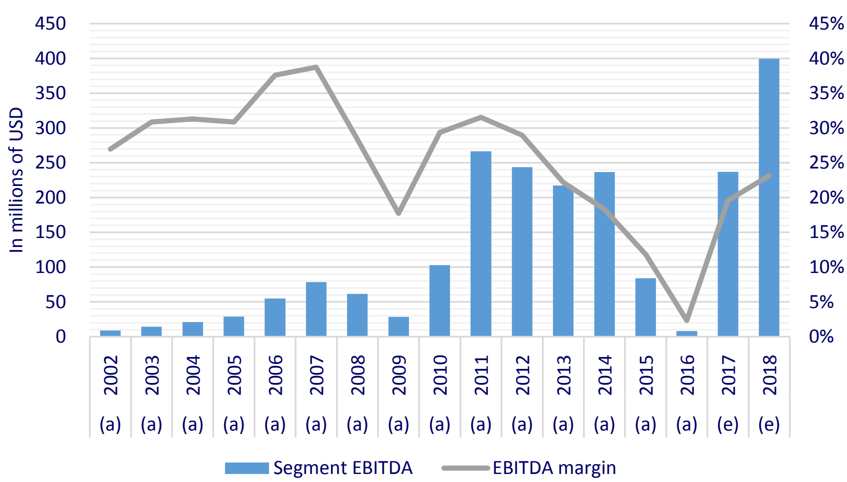
Among the best equipped to restore earnings power among the land drillers

Improved drilling efficiencies and enhanced completion designs have enabled US producers to drill a higher cadence of more productive wells using fewer rigs. This has undermined the earnings power of the land drilling industry and has forced its key players to devise strategies that will reestablish them in the value chain. For PTEN, the earnings power of the company is better off than its peers in our view as its revenue mix has evolved away from land drilling and into pressure pumping over the last decade. The company is taking more steps to broaden its offering with the recent acquisition of MS Energy, which is a leading provider of directional drilling services in the US.

Leverage to pressure pumping restoring EBITDA and margins

We believe PTEN offers more earnings leverage than any of its land drilling peers in an otherwise challenging oilfield cycle. The company has taken its pressure pumping capacity from less than 200k hhp in 2009 to about 1.5 million, which we forecast will generate $400 million of EBITDA in 2018. PTEN should exit 2017 with 23 active frac spreads representing about 80% of its horsepower following the reactivation of two spreads in 2Q17, two in 3Q17, and one more in 4Q17. The initial reactivations were $2 million apiece, the latest were $3 million and the next three are expected by the company to be $4-5 million apiece.

Figure 489: PTEN pressure pumping EBITDA and margins

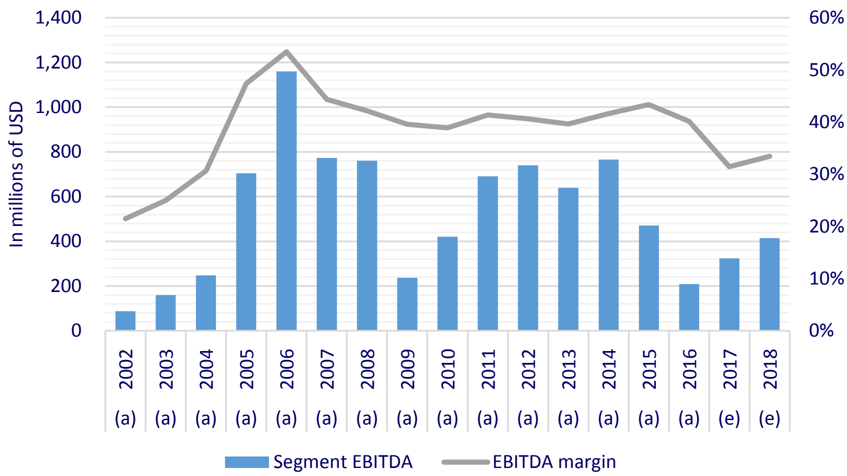


Source: Company reports, Deutsche Bank

Top echelon of the land drilling market

The bifurcation of the land drilling market is forcing the industry's mechanical and SCR rigs into retirement, some sooner rather than later. PTEN repositioned its fleet starting ten years ago and with its fleet of 198 proprietary APEX rigs, PTEN is managing to push utilization higher than the industry average while also getting pricing, albeit small.

Figure 490: PTEN contract drilling EBITDA and margins

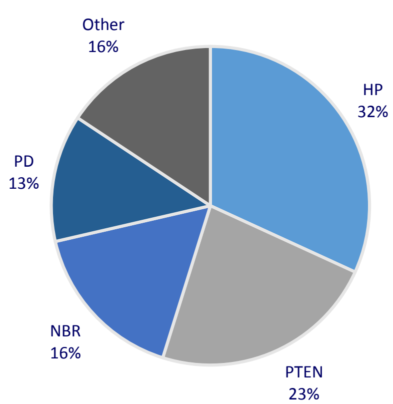


Source: Company reports, Deutsche Bank

A leading provider of the high demand super-spec rigs

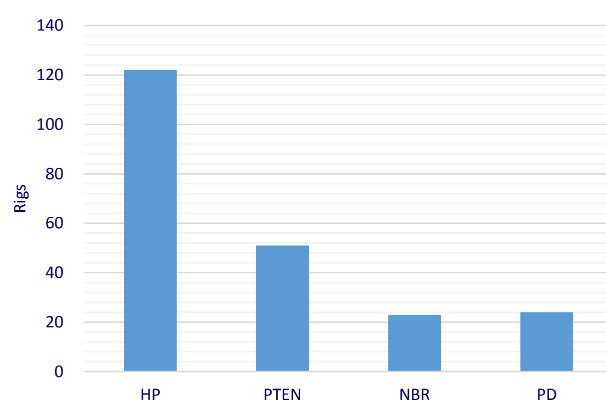
PTEN is the second largest provider of super-spec rigs with 107 as of 2Q17, which is 23% market share. Pricing is about $2,000 per day higher than the 1,500hp AC-electric rigs and producers are still saying capacity of super-spec rigs is tight. The company is upgrading seven of its APEX 1000 rigs that were in the Appalachia region, and is moving them to West Texas. The upgrades are $8 million per rig and the company has contracts for five of the seven ranging from 18 to 24 months with rates at the low $20,000 per day level.

Figure 491: Super-spec rig market share



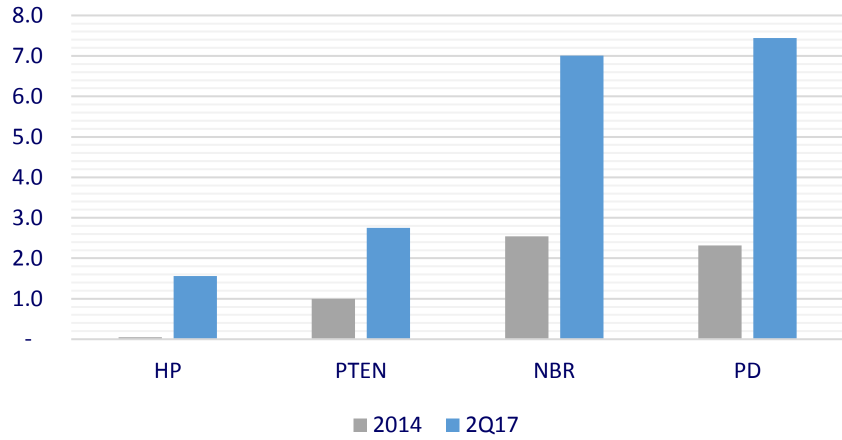
Source: Company reports, Deutsche Bank

Figure 492: Inventory of super-spec upgrade candidates



Source: Deutsche Bank

Figure 493: Debt turns…PTEN has strong relative fiscal stability



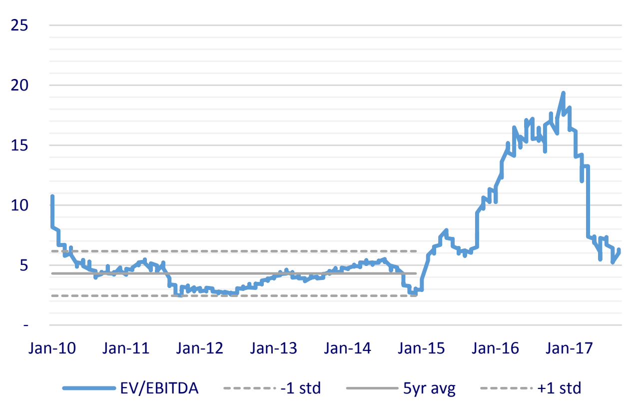
Source: Company reports, Deutsche Bank

Valuation and risks

We are initiating coverage of Patterson-UTI with a $25 price target. This is 5.0x our estimate of the company's normalized EBITDA of $1.1 billion, which is a half-turn higher than the 4.3x five-year average multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 5.6x our fiscal 2018 EBITDA estimate of $0.78 billion, and 4.1x our 2019 EBITDA estimate of $0.96 billion. We believe the half-turn premium is warranted due its peer leading leverage to the cycle with its higher mix of pressure pumping revenues and margins.

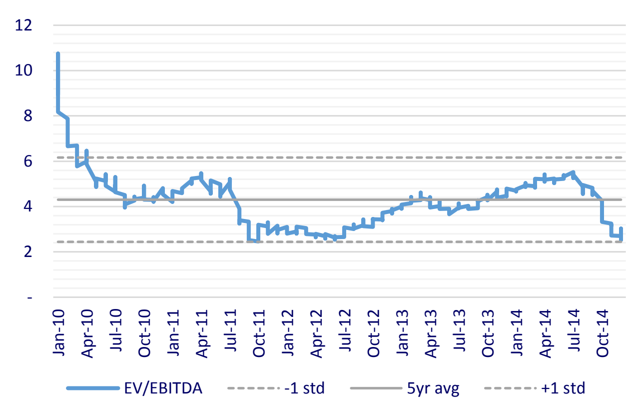
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a rapid increase in frac newbuilds, and 4) a rapid acquisition strategy that threatens the returns of the company.

Figure 494: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 495: The 5yr EV/EBITDA leading up to 2014



Source: Factset

Company description

Patterson-UTI Energy (PTEN) is the second largest land drilling company in the US where it is also a leading provider of pressure pumping services. The company markets a total of 295 land rigs including 287 in the US where it has 15% market share, and seven in Western Canada. The company is also evaluating international opportunities in the Middle East and North Africa. Its pressure pumping business consists of 1.5 million horsepower in Texas, the Appalachia region and the mid-continent.

Figure 496: Company reporting segments

Patterson-UTI Energy

Contract Drilling
- United States - 287 land rigs
- Canada - 7 land rigs

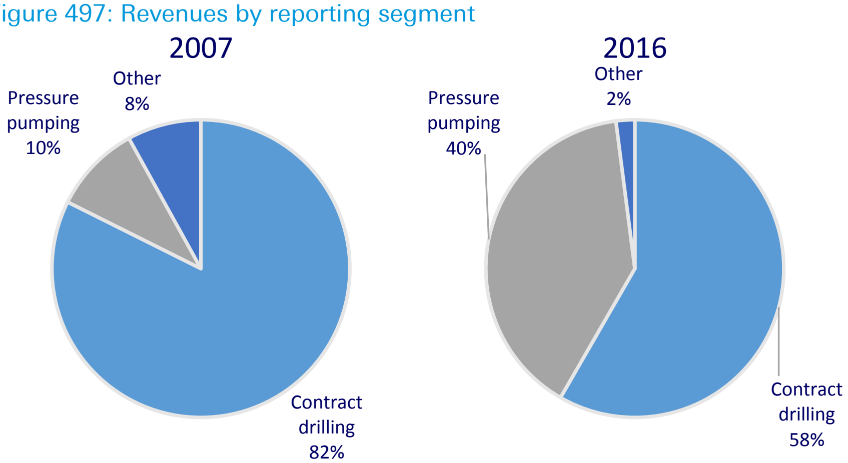
Pressure Pumping
- Texas - 850k horsepower
- Appalachia - 350k horsepower
- Mid-continent - 300k horsepower

Other
- Warrior Rig Technologies
  - Top drives, drawworks
  - Pipe handling tools, Catwalks
- Great Plains Oilfield Rental
  - BOPs, drill pipe, drill collars
  - Water delivery, pumps, frac tanks
- MS Energy Services
  - Directional drilling services

Source: Deutsche Bank

PTEN also has a rental tools business through its Great Plains Oilfield Rental subsidiary, and an equipment manufacturer, Warrior, which provides rig components including top drives, drawworks and pipe handling tools. The company recently acquired MS Energy Services, which is a leading provider of directional drilling in the US. The company's acquisitions of Seventy-Seven Energy, Warrior and now MS Energy are all aligned with its strategy to reestablish PTEN in the oilfield services value chain.

Figure 497: Revenues by reporting segment

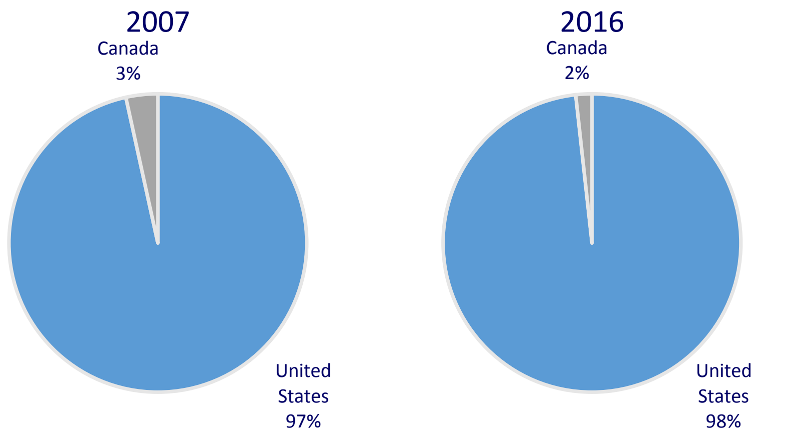


Source: Company reports

Principal Sources and Uses of Cash Flow

PTEN's principal market is the United States, where it generates approximately 98% of its revenue. But its principal source of cash flow in the US has evolved significantly over the past decade. Historically PTEN has been highly geared to the commoditized mechanical rig market, with only about 10% of its revenues coming from pressure pumping services. But for the last ten years, the company has intensely focused on its competitive positioning both in the land drilling market as well as in the overall oilfield services value chain.

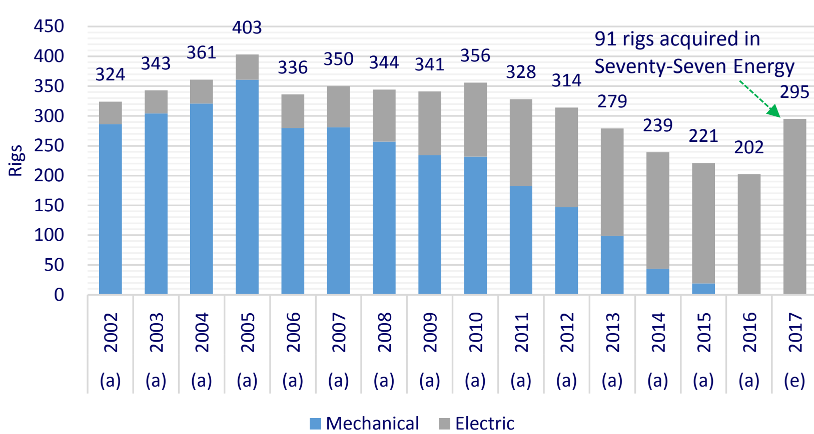
Figure 498: Geographic revenue mix



Source: Company reports

PTEN combined a history of acquisitions with a newbuild strategy that has transformed the company. Ten years ago, PTEN had 350 land rigs, 80% of which were mechanical rigs. Since then, all of its mechanical rigs have been retired and the company has organically and through acquisitions added 239 electric rigs including 199 of its proprietary APEX rigs.

Figure 499: Trend in composition of land rig fleet



Source: Company reports, Deutsche Bank

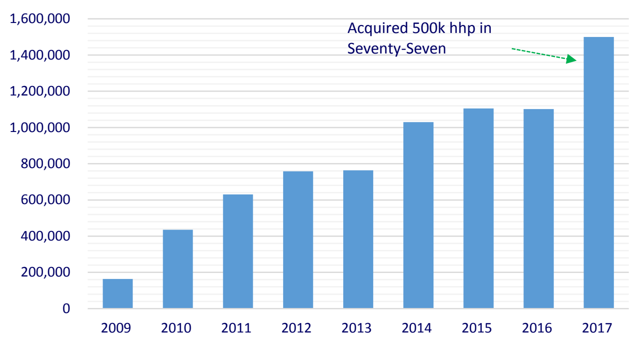
Figure 500: Composition of land rig fleet as of 2Q17

Classification	US	CN	Total	Pad rigs	% pad
From Patterson-UTI					
APEX-XK 1500®	57	0	57	53	93%
APEX 300-Series®	49	0	49	49	100%
APEX 1500®	44	1	45	11	24%
APEX 1000®	11	0	11	8	73%
APEX-XC™ (1)	1	0	1	1	100%
Total APEX class rigs	162	1	163	122	75%
From Seventy Seven Energy (SSE)					
PeakeRigs™	28	0	28	28	100%
Other AC drive rigs	12	0	12	9	75%
Total AC drive rigs (2)	40	0	40	37	93%
Other electric rigs					
Patterson-UTI Energy	35	6	41	8	20%
Seventy Seven Energy	51	0	51	35	69%
Total other electric	86	6	92	43	47%
Combined rig fleet	**288**	**7**	**295**	**202**	**68%**
Total APEX class rigs (1) (2)	198	1	199	158	79%

Source: Company reports, Deutsche Bank

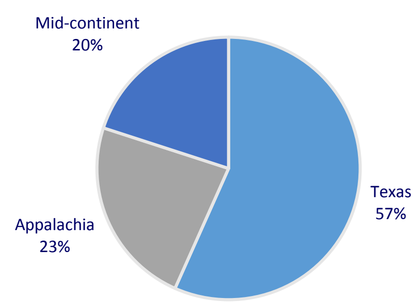
In pressure pumping, the company has added about 1.4 million horsepower over the same period, elevating revenues from 10% of the total in 2007 to 40% in 2016. We expect pressure pumping revenues will be over half of the revenue mix in 2018, carrying an EBITDA margin of about 23%. About 500k horsepower was acquired in the mid-continent in the acquisition of Seventy-Seven Energy that closed earlier in 2017.

Figure 501: Pressure pumping horsepower growth



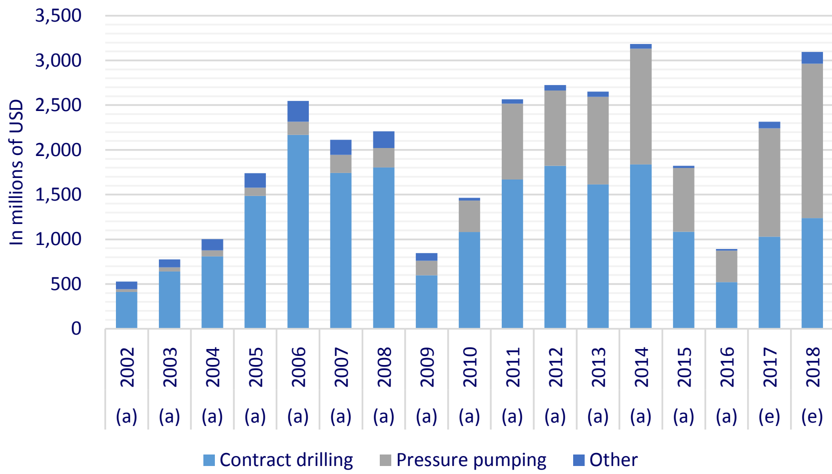
Source: Deutsche Bank

Figure 502: Geographic distribution of pressure pumping



Source: Deutsche Bank

Figure 503: Pressure pumping and other services growing in the revenue mix

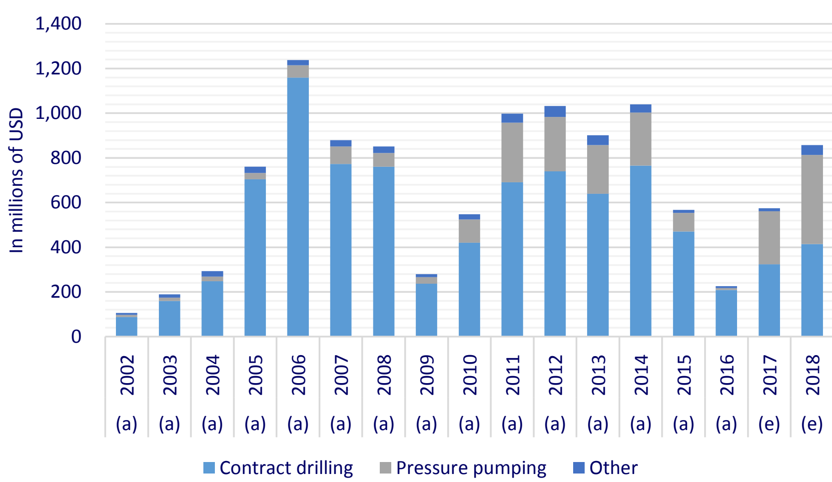


Source: Company reports, Deutsche Bank

Diversifying cash flow streams

Now PTEN has two core businesses with very different scarcity values, and is building a third with the acquisitions of more service content. The scarcity value of the land rigs has diminished severely, with the exception of super-spec rigs, which are above 90% utilization. PTEN has 107 super-spec rigs, or about 23% of the market. The company does not intend to fund newbuilds at this point, but does intend to continue upgrading rigs to super-spec capabilities. PTEN is upgrading seven of its APEX 1000 rigs to super-spec at a cost of $7-8 million apiece. We believe the company has another 50 or so APEX rigs it can upgrade.

Figure 504: EBITDA trends



Source: Company reports, Deutsche Bank

Figure 505: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues											
Contract drilling	599	1,082	1,670	1,822	1,614	1,839	1,084	521	1,036	1,250	1,390
Pressure pumping	161	351	846	842	979	1,293	712	354	1,211	1,727	1,779
Other	86	30	51	60	57	50	25	18	75	131	174
Total revenues	847	1,463	2,566	2,723	2,651	3,182	1,822	893	2,321	3,108	3,343
Segment EBITDA											
Contract drilling	237	421	691	740	640	766	470	209	325	418	521
Pressure pumping	29	103	267	244	217	237	84	8	237	400	437
Other	14	23	41	49	44	37	13	8	13	44	87
Corporate	(29)	(35)	(40)	(41)	(49)	(54)	(53)	(49)	(64)	(74)	(76)
Total EBITDA	250	512	958	991	853	986	515	176	511	787	969
D&A	281	333	437	514	560	624	702	668	758	816	822
EBIT	(31)	179	521	477	293	362	(188)	(492)	(247)	(29)	147
Interest (expense)	(4)	(8)	(16)	(22)	(28)	(30)	(36)	(40)	(37)	(37)	(34)
Interest income	0	2	0	1	1	1	1	0	2	3	3
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	(7)	3	6	6	5	16	11	13	8	8	8
PBT	(42)	175	511	462	271	349	(213)	(519)	(274)	(56)	123
Income tax (expense)	15	(66)	(188)	(171)	(99)	(113)	73	180	101	21	(46)
Non-controlling interest	0	0	0	0	0	0	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	(27)	108	323	291	171	236	(140)	(339)	(173)	(35)	77
Discontinued ops	(2)	0	(0)	0	0	0	0	0	0	0	0
Unusual after-tax	(9)	9	0	8	14	(21)	(155)	16	(46)	0	0
Net income (GAAP)	**(38)**	**117**	**323**	**299**	**186**	**216**	**(295)**	**(323)**	**(219)**	**(35)**	**77**
Operating EPS	**(0.18)**	**0.71**	**2.08**	**1.92**	**1.18**	**1.62**	**(0.96)**	**(2.32)**	**(0.91)**	**(0.17)**	**0.38**
GAAP EPS	(0.25)	0.76	2.08	1.97	1.27	1.48	(2.02)	(2.21)	(1.15)	(0.17)	0.38
DPS	0.20	0.20	0.20	0.20	0.20	0.40	0.40	0.16	0.08	0.08	0.08
Diluted shares	152	154	155	152	146	146	146	146	191	201	201
EBITDA margin	29.6%	35.0%	37.3%	36.4%	32.2%	31.0%	28.2%	19.7%	22.0%	25.3%	29.0%
EBIT margin	-3.6%	12.2%	20.3%	17.5%	11.1%	11.4%	-10.3%	-55.1%	-10.7%	-0.9%	4.4%
Tax rate	36.3%	38.0%	36.8%	37.0%	36.7%	32.3%	34.3%	34.7%	36.8%	37.5%	37.5%
Contract Drilling:											
Rigs working	91	168	216	221	192	211	124	64	140	167	174
Rigs available	341	356	328	314	279	239	221	202	295	295	295
Utilization	27%	47%	66%	70%	69%	88%	56%	32%	48%	57%	59%
Daily revenue	17,948	17,666	21,201	22,536	23,089	23,881	24,021	22,071	20,216	20,508	21,835
Daily margin	7,233	6,960	8,849	9,231	9,235	10,028	10,535	9,111	6,459	6,945	8,271
EBITDA margin											
Contract Drilling	39.6%	38.9%	41.4%	40.6%	39.6%	41.6%	43.3%	40.2%	31.4%	33.4%	37.5%
Pressure Pumping	17.7%	29.4%	31.5%	29.0%	22.2%	18.3%	11.8%	2.3%	19.6%	23.1%	24.5%

Source: Deutsche Bank

Figure 506: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	(27)	108	323	291	171	236	(140)	(339)	(174)	(37)	74
Depreciation	281	333	437	514	560	624	702	668	758	816	822
Deferred tax	101	147	159	160	51	44	(100)	(152)	(91)	0	0
Chg in receivables	214	(178)	(183)	53	12	(214)	441	72	(254)	(36)	(45)
Chg in inventories	14	(9)	(13)	5	1	(6)	40	6	(39)	(1)	(1)
Chg in payables	(53)	50	42	(25)	11	87	(132)	12	126	6	7
Other	(77)	74	104	7	83	(42)	187	38	6	8	10
Cash from operations	454	526	869	1,005	889	729	999	305	334	756	868
Capital expenditures	(453)	(738)	(1,012)	(974)	(662)	(1,052)	(744)	(120)	(580)	(525)	(433)
Free cash flow	1	(212)	(143)	31	226	(324)	256	185	(247)	232	435
Acquisitions	0	(238)	0	0	0	(176)	0	0	(434)	0	0
Asset sales	3	29	22	66	10	33	21	22	35	0	0
Dividends paid	(31)	(31)	(31)	(30)	(29)	(58)	(59)	(24)	(16)	(16)	(16)
ESPP | options	1	1	17	1	7	31	0	0	0	0	0
Equity issuance, net	(2)	(2)	(4)	(170)	(74)	(14)	(8)	(4)	468	0	0
Debt issuance, net	0	399	104	196	(1)	293	(132)	(255)	215	(150)	(65)
Other	(4)	32	32	(7)	(1)	8	(7)	(3)	0	0	0
Chg in cash	(31)	(22)	(4)	87	139	(206)	70	(78)	22	65	354
FCF per share	0.01	(1.38)	(0.92)	0.21	1.55	(2.22)	1.75	1.27	(1.29)	1.15	2.16
Capex / revenue	0.53	0.50	0.39	0.36	0.25	0.33	0.41	0.13	0.25	0.17	0.13
Capex / depreciation	1.61	2.21	2.31	1.89	1.18	1.69	1.06	0.18	0.77	0.64	0.53

Source: Deutsche Bank

Figure 507: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	50	28	24	111	250	43	113	35	57	122	476
Accounts receivable	164	337	518	466	452	663	220	148	552	588	632
Inventories	7	17	31	27	21	32	15	20	46	47	48
Other current assets	236	175	192	97	86	170	139	80	80	85	92
Total current assets	457	557	765	700	809	909	487	283	734	842	1,248
Net PP&E	2,110	2,621	3,167	3,615	3,636	4,131	3,921	3,409	4,214	3,923	3,534
Goodwill	86	180	176	171	167	221	93	89	540	540	540
Other assets	8	65	114	70	75	133	33	23	77	82	88
Total assets	2,662	3,423	4,222	4,557	4,687	5,394	4,533	3,805	5,565	5,387	5,410
Accounts payable	84	162	242	189	173	382	83	126	323	329	337
Current debt	0	6	10	6	10	13	64	0	0	0	0
Other current liabilities	110	147	167	165	171	173	162	139	280	298	321
Total current liabilities	193	316	419	360	354	568	308	265	603	627	657
Long-term debt	0	393	493	693	683	973	791	598	814	664	599
Other LT liabilities	580	843	1,213	1,224	1,249	1,515	1,181	957	1,206	1,231	1,261
Shareholders' equity	2,082	2,188	2,517	2,641	2,756	2,906	2,561	2,249	3,546	3,493	3,551
Total liabilities and equity	2,662	3,423	4,222	4,557	4,687	5,394	4,533	3,805	5,565	5,387	5,410
Total debt	0	399	503	699	693	986	855	598	814	664	599
Net debt	(50)	371	479	588	443	942	742	563	757	541	122
Debt/capital	0%	15%	17%	21%	20%	25%	25%	21%	19%	16%	14%
Debt/equity	0%	18%	20%	26%	25%	34%	33%	27%	23%	19%	17%
Debt turns	**0.0**	**0.8**	**0.5**	**0.7**	**0.8**	**1.0**	**1.7**	**3.4**	**1.6**	**0.8**	**0.6**

Source: Deutsche Bank

Rating
Hold

North America
Canada

Industrials
Oil Services & Equipment

Company
Precision Drilling

Reuters	Bloomberg
PD.TO	PD CN

David Havens
Research Analyst
+1-212-250-3235
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Price at 5 Oct 2017 (CAD)	3.57
Price target	4.00
52-week range	7.86 - 3.02

Capital upgrades focusing on US land fleet

Initiating coverage with a Hold rating and a $4 price target

The drilling more with less trend in the US has the company pivoting from a newbuild strategy to an upgrade strategy as it looks to continue growing its US market share. We expect overall US rig activity to flatten in 2018, creating a challenging environment to recreate the customary pricing leverage we have become accustomed to in land drilling. Canadian activity has Precision's revenue mix leaning toward the shallower basins, where dayrate traction has thus far not had any success.

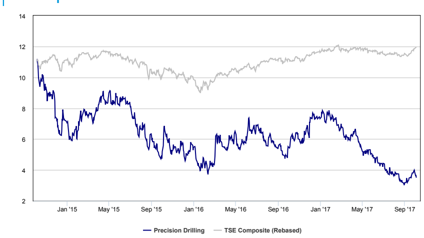
Commodity prices are deflating the Precision's customary drilling leverage

Not only are producers drilling more with less, but now the US is exerting more influence on global oil markets than it has in over 30 years. We believe this will confine oil prices to a range of $40-55 through 2018. This combined with all of its peers also looking to upgrade rigs in the US in an otherwise flat market in 2018 undermines Precision's earnings power as it looks to add value via technology.

Highly levered balance sheet, but pivoting to positive free cash flow in 2017

Precision exited 2Q17 with 7.4 debt turns, up more than 3x from where it was in 2014. This should decline through 2018 in our view to about 4.7 turns. We expect free cash flow to be positive in 2017 and 2018 by almost CAD$200 million.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	10.8	-20.3	-36.1
TSE Composite	3.5	3.9	8.3

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (CADm)	1,046.9
Shares outstanding (m)	293.2
Free float (%)	100
Volume (5 Oct 2017)	2,393,476
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.12	-0.08A	-0.04
2Q EPS	-0.19	-0.12A	-0.11
3Q EPS	-0.17	-0.08	-0.03
4Q EPS	-0.10	-0.07	0.02
FY EPS (CAD)	-0.58	-0.35	-0.15
OLD FY EPS (CAD)	-0.57	–	–
% Change	1.9%	–	–
P/E (x)	–	–	–
DPS (CAD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (CADm)	928.8	1,372.6	1,763.4

Source: Deutsche Bank estimates, company data

Valuation

Our $4 price target is 5.2x our estimate of the company's normalized EBITDA of $0.5 billion, which is in-line with the 5.2x five-year average multiple leading up to the 2014 collapse in oil prices. Valuations have consolidated due to the high leverage in our view as markets reassess the earnings power. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) a derailing of PD's efforts to capture incremental margin from its control system and process automation software.

Key investment themes

Upgrades and market share are the focus

Improved drilling efficiencies and enhanced completion designs have enabled US producers to drill a higher cadence of more productive wells using fewer rigs. This has undermined the earnings power of the land drilling industry and has forced its key players to devise strategies that will reestablish them in the value chain. Precision sees the best opportunity being market share in the US and rig upgrades that will add to the daily rig rate.

Vying market share growth in the US onshore

Part of Precision's strategy is to continue market share growth in the US. The company does not intend to fund newbuilds in this environment, but it does view upgrades in the US as a core opportunity. This includes upgrading its Super Triples with NOVOS process automation controls, 20 of which have already been done. The company expects this upgrade to fetch an added $1,500 per day. Overall, Precision's capital program has targeted 35 Super Triple upgrades at an average of CAD$1.5 million per rig. As the company moves towards the back-end of its fleet, it expects per rig cost to rise to CAD$7-8 million.

Regional mix pressuring Precision's dayrates in Canada

There are fewer rigs working under legacy contracts and a higher proportion of revenue coming from the shallower Canadian plays (Southern Saskatchewan and Central /Southern Alberta regions) that have dayrates in the low teens. Pricing in the shallow parts of Western Canada remains challenged due to excess supply, and Precision's efforts to push higher have not worked. Where Precision has gotten increased pricing is in the deeper basins (Montney and Duvernay). The company is getting low $20s for Super Triples and Super Triple 1500s, and high-teens for Super Triple 1200s. Super Triples earn 2x the EBITDA as smaller rigs. We expect only moderate pricing in Canada in 2018.

Commodity prices have dampened the broad North America recovery

But it is also sustaining the focus on rig efficiencies and best practices. Precision is looking to showcase its technologies including pad walking systems, extended reach horizontal drilling, AMPHION AC control systems, process automation controls, directional drilling guidance software, advanced drilling applications and wired pipe.

Does not expect to realize any upside in its international segment in 2H17

Most of Precision's efforts are focusing on operations, i.e. rig performance, rig move times, and operating costs. Management believes customer demand may be bottoming and it is seeing some green shoots in the Middle East and Latin America, but not Mexico. The company has four idle rigs in the Middle East and five idle rigs in Mexico that they are actively bidding.

Precision is focusing on rejuvenating free cash flow and reducing debt

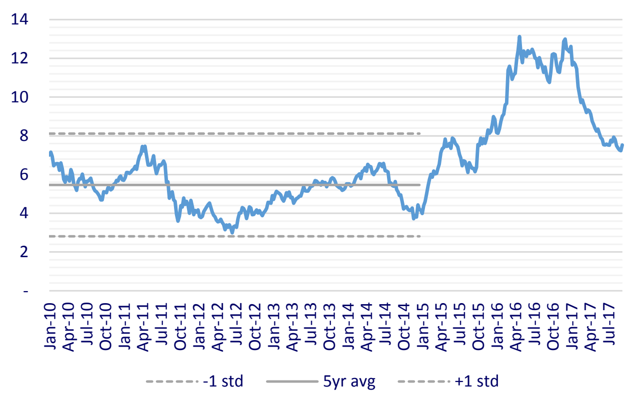
Since 2011, the company on a cumulative basis has been free cash flow negative by about CAD$0.66 billion and debt turns have risen to 7.4x, one of the highest amongst the land drilling peers. We do expect the company to be free cash flow positive in 2017 and 2018 by a combined CAD$0.2 billion and for debt turns to drop to 4.7x by year-end 2018.

Valuation and risks

Our $4 price target is 5.2x our estimate of the company's normalized EBITDA of $0.5 billion, which is in-line with the 5.2x five-year average multiple leading up to the 2014 collapse in oil prices. Valuations have consolidated due to the high leverage in our view as markets reassess the earnings power.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) a derailing of PD's efforts to capture incremental margin from its control system and process automation software..

Figure 508: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 509: The 5yr EV/EBITDA leading up to 2014

Source: Factset

Company description

Precision Drilling Corporation (PDS) is a contract drilling and well servicing company with operations in the US, Canada, Mexico and the Middle East. Precision's core business is land drilling with a fleet of 256 rigs, which accounted for 86% of revenues in 2016, excluding the 3% from the directional drilling business. In the US, Precision has 103 land rigs and is the fourth largest contractor with 7% market share. In Canada, Precision in the largest land driller with 136 land rigs and 29% market share. Precision's international operations were 18% of 2016 revenues and include 17 land rigs. Its directional drilling business, which is included in the Contract Drilling segment, provides services in the US as well as Canada.

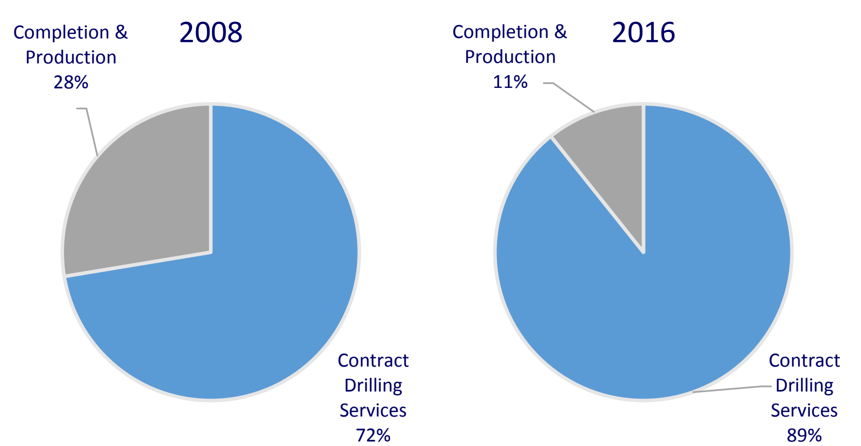
Figure 510: Company reporting segments

Precision Drilling Corporation	
Contract Drilling Services	**Completion & Production Services**
- Canada - 136 land rigs	- Completion and workover service rigs
- United States - 103 land rigs	- Canada - 191 service rigs
- International - 17 land rigs	- United States - 8 service rigs
- Directional drilling services	- Snubbing units (11 in Canada)
- Canada	- Equipment rentals (Canada and US)
- United States	- Camps and catering (Canada)
	- Water systems (Canada)

Source: Deutsche Bank

Precision's Completion and Production segment includes the largest well servicing fleet in Canada where it has 191 of its 199 well servicing rigs, and all 11 of its snubbing units. Well servicing in Canada and the US was 7% of 2016 revenues. The other 4% included Precision Rentals, LRG Camp and Catering, and Terra Water Systems.

Figure 511: Revenues by reporting segment

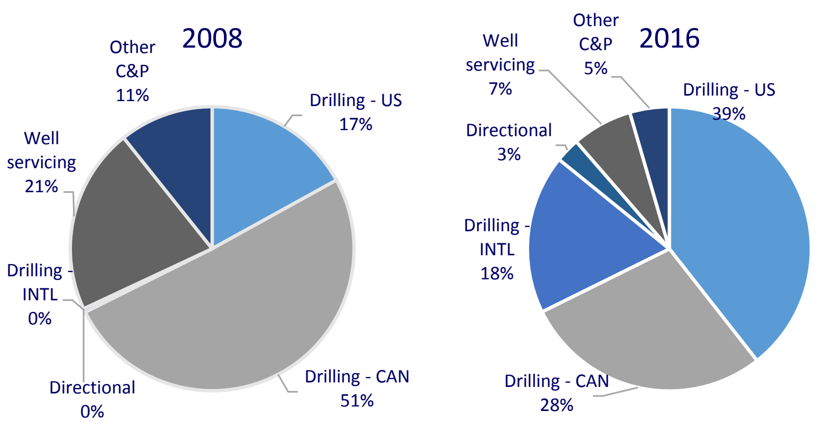


Source: Company reports

Principal Sources and Uses of Cash Flow

Precision's core business is land drilling and its two principal markets are the US and Canada. US land drilling has grown within Precision from 17% of 2008 revenues to 39% of 2016 revenues due to the acquisition of Grey Wolf in 2008 and a major newbuild and upgrade campaign that started in 2011. International land drilling has also grown from nothing in 2008 to 18% of 2016 revenues. Precision has 17 rigs in international markets including Mexico (5), Kuwait (5), Saudi Arabia (4), Kurdistan (2) and Georgia (1).

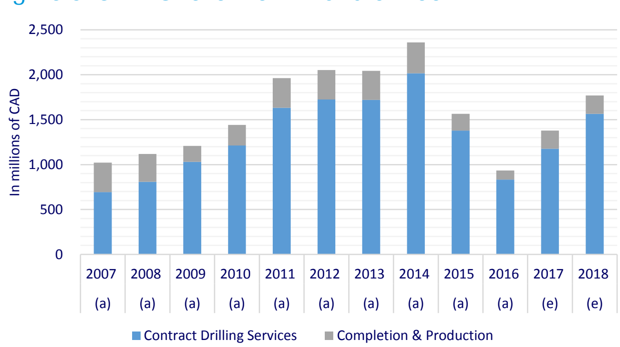
Figure 512: Revenue contribution detail



Source: Deutsche Bank

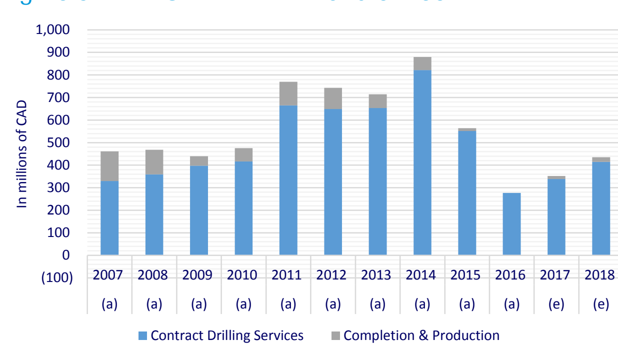
Precision's well servicing business has declined in its contribution from 21% in 2008 to 7% in 2016. Precision believes this business is oversupplied and highly competitive, with pricing the key differentiator. The company does see its scale and cost leverage as competitive advantages, but the business has not been profitable at the EBIT level since 2015. While management is focusing on more cost reductions, this is a business that is highly responsive to commodity price changes.

Figure 513: PDS revenue mix and outlook



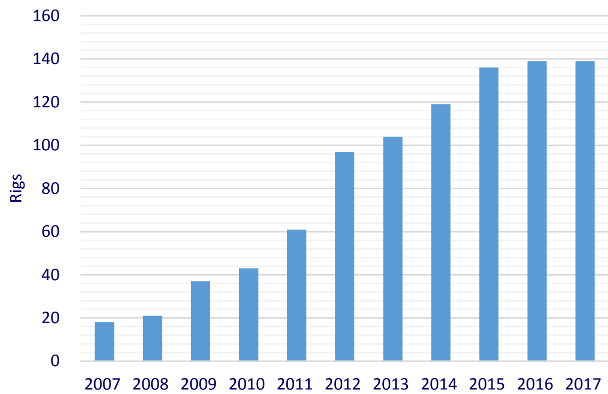
Source: Company reports, Deutsche Bank

Figure 514: PDS EBITDA mix and outlook



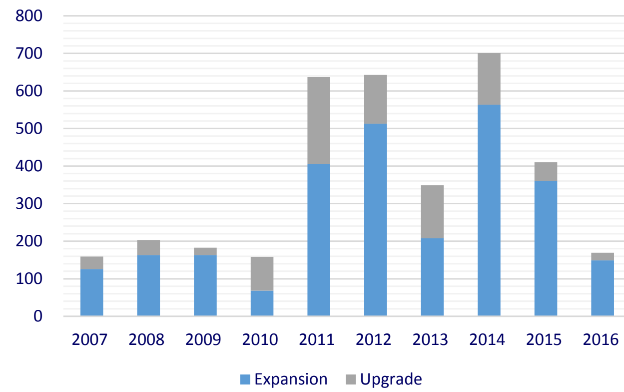
Source: Company reports, Deutsche Bank

Figure 515: Super Series rig expansion campaign



Source: Company reports, Deutsche Bank

Figure 516: Contract drilling expansion and upgrade capex



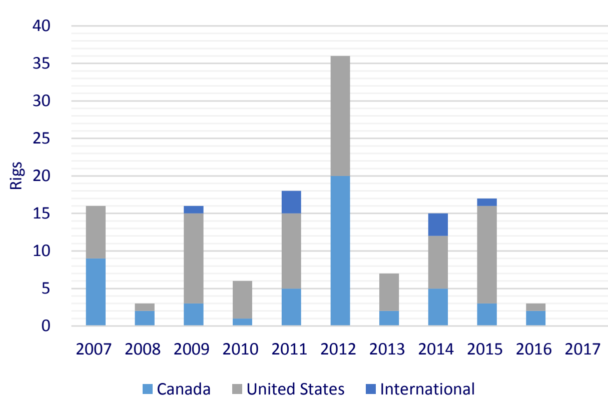
Source: Company reports, Deutsche Bank

Fleet expansion has been core to Precision's strategy, especially in the US

Precision's strategy is to concentrate on market share growth in the US and to commercialize rig automation and efficiency driven technologies across its Super Series fleet. Prior to the drop in oil prices, Precision had launched a significant rig expansion and upgrade program that added 139 Super Series rigs over the last ten years. The company spent about CAD$2.9 billion on its Super-Series expansion over that period and about CAD$0.9 billion on upgrades. Just since 2011, the company added 99 of these newbuilds and 21 major upgrades for a net 120 tier 1 rigs for CAD$2.9 billion. Precision decommissioned 196 legacy rigs over that same period.

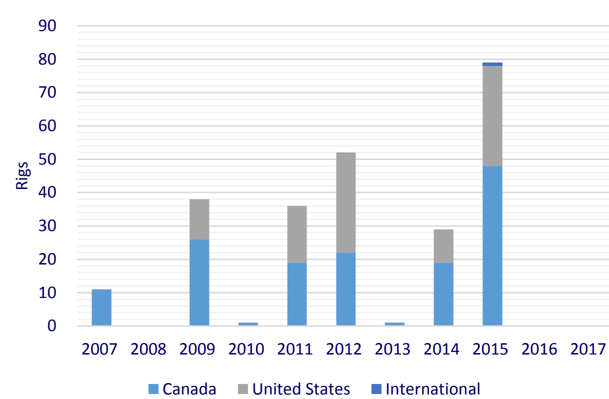
Going forward, Precision sees upgrades in the US as the core opportunity. The company is looking to upgrade its Super Triples with its NOVOS process automation, which the company believes can add $1,500 per day to the rate. So far 20 have been done and the company has targeted 35 Super Triple upgrades at an average of CAD$1.5 million per rig. As Precision moves to the back half of its fleet, upgrade costs will escalate to CAD$7-8 million per rig according to management.

Figure 517: Drilling rigs added by geography



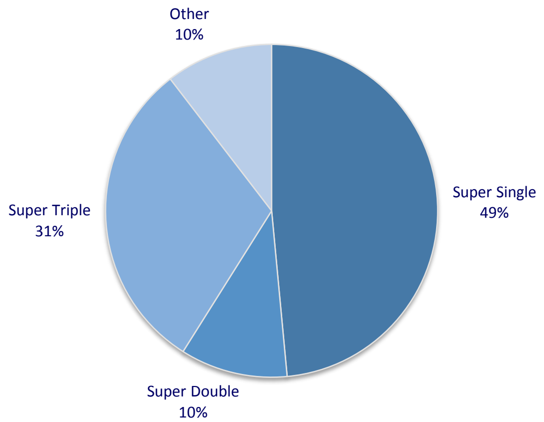
Source: Company reports, Deutsche Bank

Figure 518: Drilling rigs retired by geography



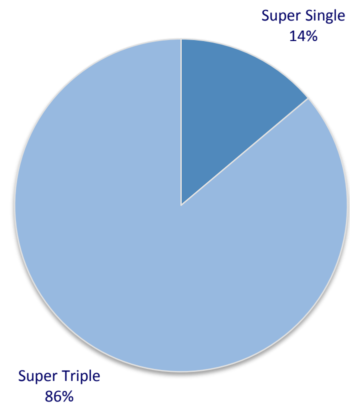
Source: Company reports, Deutsche Bank

Figure 519: Precision's Canadian rig fleet (136 rigs)



Source: Company reports, Deutsche Bank

Figure 520: Precision's US rig fleet (103 rigs)



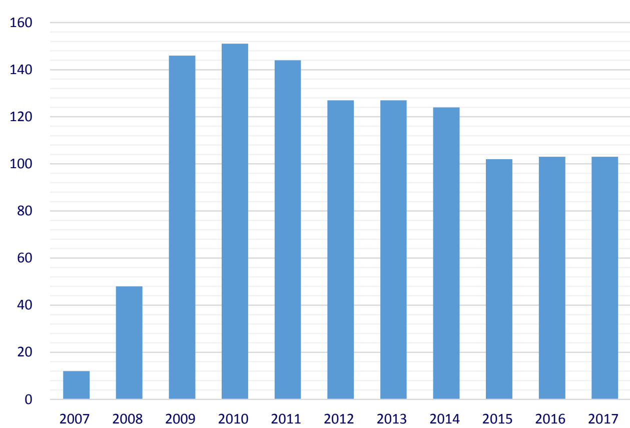
Source: Company reports, Deutsche Bank

Technology is core to Precision

Precision has been investing in technology for its rigs in a competitive repositioning effort for over ten years. Starting with the investment in AC-electric rigs in 2006 (106 AC rigs currently with 20 upgrade candidates) and the addition of walking systems in 2008, the company went on to add integrated directional drilling, wired pipe and process automation control.

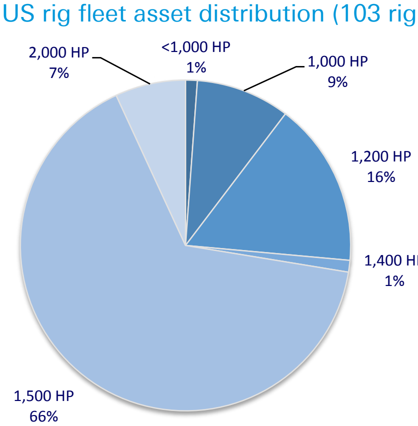
Precision is in the midst of adding its NOVOS Process Automation Control (PAC) to its AC fleet. The company targeted 20 rigs by year-end 2017 with full deployment across all AC rigs by mid-2019. The company is also partnered with Schlumberger and Pason for its directional guidance system (DGS). Precision also uses wired pipe for improved downhole transmission rates and is investing in Big Data analytics and machine leaning to improve rig efficiencies and deploy predictive maintenance.

Figure 521: Net changes to US rig fleet



Source: Company reports, Deutsche Bank

Figure 522: US rig fleet asset distribution (103 rigs)



Source: Company reports, Deutsche Bank

Figure 523: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of CAD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenue:											
Contract Drilling Services	1,031	1,213	1,632	1,725	1,720	2,017	1,378	833	1,176	1,566	2,270
Completion & Production	176	228	330	326	323	344	186	100	202	204	204
Eliminations	(10)	(11)	(11)	(11)	(13)	(10)	(9)	(5)	(5)	(6)	(9)
Total revenues	1,197	1,430	1,951	2,041	2,030	2,351	1,556	929	1,373	1,763	2,465
Segment EBITDA:											
Contract Drilling Services	397	417	665	649	654	821	551	277	339	415	544
Completion & Production	42	59	104	94	61	58	12	(2)	13	20	20
Corporate, other	(33)	(40)	(75)	(72)	(76)	(79)	(72)	(64)	(46)	(43)	(42)
EBITDA	407	435	695	671	639	800	491	211	306	392	522
D&A	138	183	251	308	333	432	487	392	377	353	339
EBIT	269	253	444	363	306	369	5	(180)	(71)	39	183
Interest (expense)	(138)	(96)	(74)	(90)	(94)	(111)	(139)	(150)	(137)	(137)	(137)
Interest income	0	1	2	2	1	1	4	3	2	8	40
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	0	1	(9)	(3)	9	1	33	(6)	1	0	0
PBT	131	158	363	273	222	260	(97)	(333)	(206)	(89)	87
Income tax (expense)	(4)	(4)	(73)	(41)	(30)	(31)	64	162	104	45	(44)
Non-controlling interest	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	127	154	290	231	191	229	(33)	(171)	(102)	(44)	43
Discontinued ops	0	0	0	0	0	0	0	0	0	0	0
Unusual after-tax	34	(92)	(97)	(179)	0	(196)	(330)	16	0	0	0
Net income (GAAP)	162	62	193	52	191	33	(363)	(156)	(102)	(44)	43
Operating EPS	**0.50**	**0.55**	**1.01**	**0.81**	**0.66**	**0.78**	**(0.11)**	**(0.58)**	**(0.35)**	**(0.15)**	**0.15**
GAAP EPS	0.64	0.22	0.67	0.18	0.66	0.11	(1.24)	(0.53)	(0.35)	(0.15)	0.15
DPS	0.14	0.00	0.00	0.05	0.20	0.25	0.28	0.00	0.00	0.00	0.00
Diluted shares	256	283	289	287	288	294	293	293	293	293	293
EBITDA margin	34.0%	30.5%	35.6%	32.9%	31.5%	34.1%	31.6%	22.7%	22.3%	22.2%	21.2%
EBIT margin	22.5%	17.7%	22.7%	17.8%	15.1%	15.7%	0.3%	-19.4%	-5.2%	2.2%	7.4%
Tax rate	3.1%	2.4%	20.1%	15.2%	13.7%	11.8%	65.8%	48.5%	50.6%	50.5%	50.5%
Canada Drilling											
Rigs working	58	85	104	88	84	90	47	35	60	108	192
Rigs available	203	203	189	186	187	174	134	135	136	136	136
Utilization	29%	42%	55%	48%	45%	52%	35%	26%	44%	79%	141%
Average dayrate (CAD)	17,824	16,159	18,442	21,030	22,108	22,250	23,670	20,760	18,168	18,833	19,550
US Drilling											
Rigs working	62	89	104	95	83	96	58	31	57	61	62
Rigs available	146	151	144	127	127	124	102	103	103	103	103
Utilization	43%	59%	72%	74%	65%	77%	57%	30%	55%	59%	60%
Average dayrate (USD)	23,194	18,952	21,780	23,698	23,586	24,337	25,730	24,472	18,941	18,657	19,412
International Drilling											
Rigs working	2	2	2	6	10	11	11	8	8	9	11
Rigs available	3	3	6	8	13	15	15	17	17	17	17
Utilization	65%	55%	32%	70%	75%	74%	75%	45%	47%	54%	65%
Average dayrate (CAD)	33,448	45,248	32,755	31,152	38,729	48,436	55,369	60,763	66,805	65,144	65,144

Source: Deutsche Bank

Figure 524: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of CAD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	127	154	290	231	191	229	(33)	(171)	(102)	(44)	43
Depreciation	138	183	251	308	333	432	487	392	377	353	339
Deferred tax	15	(16)	47	(25)	30	(12)	(203)	(153)	(60)	0	0
Other	224	(16)	(56)	121	(127)	31	266	55	(4)	0	0
Cash from operations	505	305	533	635	428	680	517	123	211	309	382
Capital expenditures	(193)	(176)	(726)	(868)	(536)	(857)	(459)	(203)	(143)	(197)	(236)
Free cash flow	311	129	(194)	(233)	(108)	(177)	58	(81)	68	112	145
Acquisitions	0	0	(93)	(0)	0	0	0	(12)	0	0	0
Asset sales	16	12	16	31	13	102	10	8	6	0	0
Dividends paid	(27)	0	0	(14)	(58)	(73)	(82)	0	0	0	0
ESPP | options	0	0	2	2	2	7	0	2	0	0	0
Equity issuance, net	413	(0)	0	0	48	0	0	0	0	0	0
Debt issuance, net	(565)	(33)	407	0	30	406	0	(208)	0	0	0
Other	(79)	18	72	(101)	(0)	146	(33)	(37)	(46)	0	0
Chg in cash	69	126	211	(315)	(72)	411	(47)	(329)	27	112	145
FCF per share	1.22	0.46	(0.67)	(0.81)	(0.37)	(0.60)	0.20	(0.28)	0.23	0.38	0.50
Capex / revenue	0.16	0.12	0.37	0.43	0.26	0.36	0.29	0.22	0.10	0.11	0.10
Capex / depreciation	1.40	0.96	2.89	2.82	1.61	1.98	0.94	0.52	0.38	0.56	0.70

Source: Deutsche Bank

Figure 525: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of CAD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	131	257	467	153	81	491	445	116	143	255	400
Accounts receivable	284	415	576	510	550	598	312	294	407	552	771
Inventories	9	5	7	14	12	9	24	24	37	50	73
Other current assets	26	0	0	0	0	0	0	0	41	41	41
Total current assets	449	677	1,051	676	643	1,099	781	434	628	898	1,285
Net PP&E	2,914	2,812	2,942	3,243	3,562	3,929	3,883	3,642	3,332	3,176	3,073
Goodwill	761	737	364	311	312	220	208	207	206	206	206
Other assets	517	748	1,122	747	705	1,160	787	437	631	901	1,288
Total assets	4,192	4,297	4,428	4,300	4,579	5,309	4,879	4,286	4,170	4,283	4,568
Accounts payable	128	216	437	334	333	493	236	241	294	391	572
Current debt	0	0	0	0	0	0	0	0	0	0	500
Other current liabilities	0	1	4	64	4	7	8	0	0	0	0
Total current liabilities	129	217	440	398	337	500	244	241	294	391	1,072
Long-term debt	749	804	1,240	1,219	1,323	1,852	2,181	1,907	1,845	1,845	1,345
Other LT liabilities	730	698	615	512	520	515	333	214	137	137	137
Non-controlling int	0	0	0	0	0	0	0	0	0	0	0
Shareholders' equity	2,585	2,578	2,133	2,171	2,399	2,441	2,121	1,924	1,894	1,911	2,014
Total liabilities and equity	4,192	4,297	4,428	4,300	4,579	5,309	4,879	4,286	4,170	4,283	4,568
Total debt	749	804	1,240	1,219	1,323	1,852	2,181	1,907	1,845	1,845	1,845
Net debt	618	548	772	1,066	1,243	1,361	1,736	1,791	1,702	1,590	1,445
Debt/capital	22%	24%	37%	36%	36%	43%	51%	50%	49%	49%	48%
Debt/equity	29%	31%	58%	56%	55%	76%	103%	99%	97%	97%	92%
Debt turns	**1.8**	**1.8**	**1.8**	**1.8**	**2.1**	**2.3**	**4.4**	**9.0**	**6.0**	**4.7**	**3.5**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
Rowan Companies

Reuters	Bloomberg
RDC.N	RDC US

David Havens
Research Analyst
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Price at 5 Oct 2017 (USD)	13.02
Price target	15.00
52-week range	20.90 - 9.04

High-Specification Jackup Exposure

Initiating coverage with a Hold rating and an $15 price target

The main headwind for Rowan has been its rapidly eroding backlog accelerated by early terminations in its ultra-deepwater fleet. Rowan has high quality, high-specification rigs with over $1 billion in cash on the balance sheet and a JV with Saudi Aramco that provides line-of-sight to 20 newbuild jackups with 15 year term commitments. But the problem is, through 2019, EBITDA erodes aggressively to $230 million in 2018 and less than $200 million in 2019 without some big contract wins in our view.

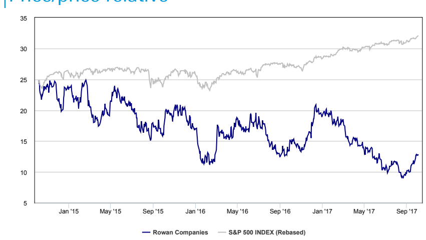
Jackup market turning up and RDC has premier rigs, but deepwater eroding

Over 80% of Rowan's backlog is in its jackup fleet, but its ultra-deepwater fleet has got zero committed days in 2019 and only 17% of its days committed in 2018. Normally we would look at the leverage some big contract wins could deliver to the stock, but the fierce pricing tactics in the deepwater market deflate a lot of that leverage.

Could see M&A going either direction

Rowan would be an attractive target given its fleet quality, but we believe Rowan is interested in being a suitor as it looks to build scale, especially in its deepwater segment. We believe Rowan is more agnostic about jackups versus drillships than many of its peers, and it would seek to do either if the right deal came about, but we expect management will look hard to build more deepwater scale at these levels.

Price/price relative



Performance (%)	1m	3m	12m
Absolute	25.9	16.3	-11.3
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,648.0
Shares outstanding (m)	126.6
Free float (%)	98
Volume (5 Oct 2017)	658,681
Option volume (und. shrs., 1M avg.)	101,868

Source: Deutsche Bank

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.98	0.07A	-0.33
2Q EPS	0.75	-0.25A	-0.38
3Q EPS	0.30	-0.21	-0.48
4Q EPS	0.07	-0.23	-0.73
FY EPS (USD)	2.10	-0.61	-1.93
OLD FY EPS (USD)	2.14	-0.76	-2.80
% Change	-1.8%	-19.6%	-31.2%
P/E (x)	7.4	–	–
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	1,723.3	1,229.1	916.9

Source: Deutsche Bank estimates, company data

Valuation & Risks

We are initiating coverage with an $15 price target. This is about 4.0x our estimate of the company's normalized EBITDA of $0.8 billion, which is two-turns below the 6.0x ten-year average multiple. The company is currently trading at 11.3x our fiscal 2018 EBITDA estimate of $0.2 billion. We believe the discounted multiple is warranted due to the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

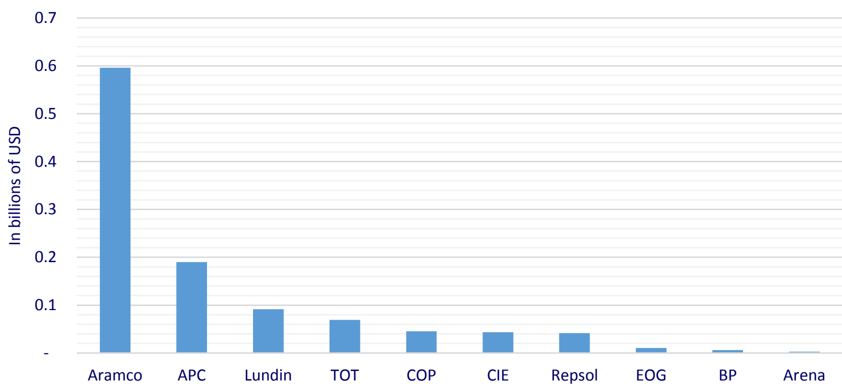
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, and 3) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Key investment themes

Jackup exposure is majority of backlog

Rowan's backlog stands at about $1.1 billion, which is down 35% from the $1.7 billion in February 2009. Approximately 80% of the backlog is in the jackup fleet, which differentiates the company relative to its deepwater heavy peers. Rowan's ultra-deepwater backlog covers only 17% of the available days in 2018 and zero in 2019. Its jackup backlog is about one-third of the total capacity.

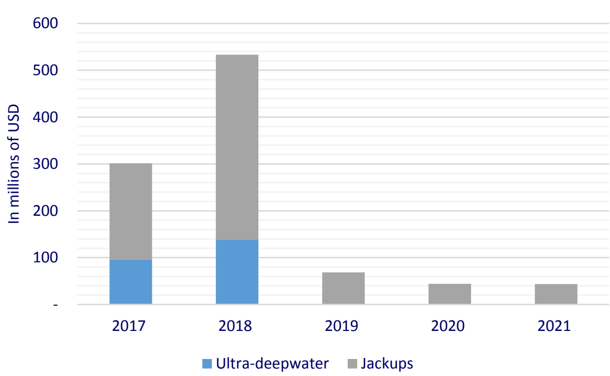
Figure 526: Backlog by customer



Source: Company reports, Deutsche Bank

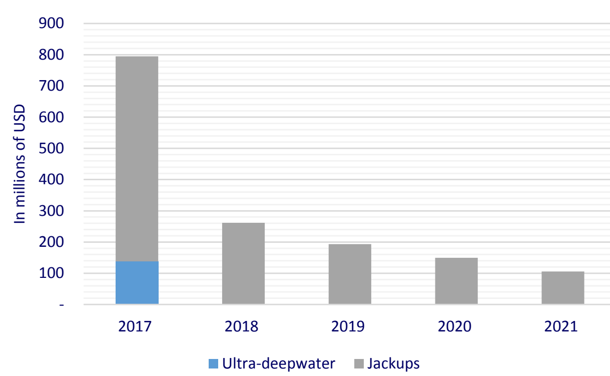
In terms of customer concentration, Saudi Aramco is the single largest client with 54% of Rowan's backlog. Rowan's top five customers are 90% of its total backlog.

Figure 527: Revenues in backlog



Source: Company reports, Deutsche Bank

Figure 528: Year-end backlog



Source: Company reports, Deutsche Bank

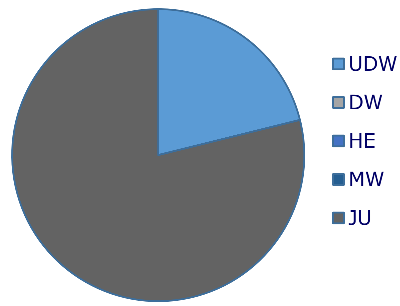
Figure 529: Rowan Companies backlog details

Revenue in backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	89	138	-	-	-
Deepwater					
Harsh-environment					
Midwater					
Jackups	190	395	68	44	44
Total backlog	**279**	**533**	**68**	**44**	**44**

Total backlog	Abbrev	($bn)
Ultra-deepwater	UDW	0.2
Deepwater	DW	-
Harsh-environment	HE	-
Midwater	MW	-
Jackups	JU	0.8
Total backlog		**1.1**

Days committed	2017	2018	2019	2020	2021
Ultra-deepwater	50%	17%	0%	0%	0%
Deepwater					
Harsh-environment					
Midwater					
Jackups	57%	34%	7%	4%	4%
Total backlog	**56%**	**31%**	**6%**	**4%**	**4%**

Backlog by rig type



Year-end backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	138	-	-	-	-
Deepwater					
Harsh-environment					
Midwater					
Jackups	657	262	194	150	106
Total backlog	**795**	**262**	**194**	**150**	**106**

	2017	2018	2019
Total debt	2,517	2,517	2,309
Debt / YE backlog	**3.2**	**9.6**	**11.9**

Backlog by customer ($m	#1	#2	#3	#4	#5
Ultra-deepwater	**APC**	**CIE**			
Backlog	186	41			
% of backlog	82%	18%			
Deepwater					
Backlog					
% of backlog					
Harsh-environment					
Backlog					
% of backlog					
Midwater					
Backlog					
% of backlog					
Jackups	**Aramco**	**Lundin**	**TOT**	**COP**	**EOG**
Backlog	590	88	68	44	10
% of backlog	70%	10%	8%	5%	1%

Top 5 customers in backlog		Percent	$bn
Aramco	#1	55%	0.6
APC	#2	17%	0.2
Lundin	#3	8%	0.1
TOT	#4	6%	0.1
COP	#5	4%	0.0
Other		**9%**	**0.1**

Fleet composition	2017	2018	2019
Ultra-deepwater	4	4	4
Deepwater	-	-	-
Harsh-environment	-	-	-
Midwater	-	-	-
Jackups	25	25	25
Total in fleet	**29**	**29**	**29**

Source: Company reports, Deutsche Bank

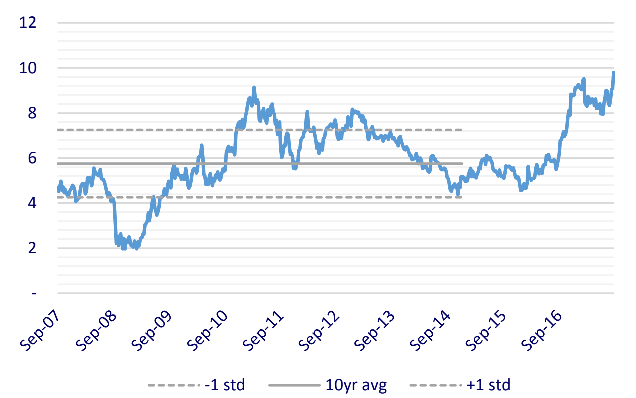
Valuation and risks

We are initiating coverage with an $15 price target. This is about 4.0x our estimate of the company's normalized EBITDA of $0.8 billion, which is two-turns below the 6.0x ten-year average multiple. The company is currently trading at 11.3x our fiscal 2018 EBITDA estimate of $0.2 billion. We believe the discounted multiple is warranted due to the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

In terms of steel value, we assess the trough net asset value at $13.00 per share, which assumes the market endures another three years of high volumes of cold-stacking once contracts expire and leading edge market rates that stay at breakeven levels ($160-170 kpd) for deepwater rigs.

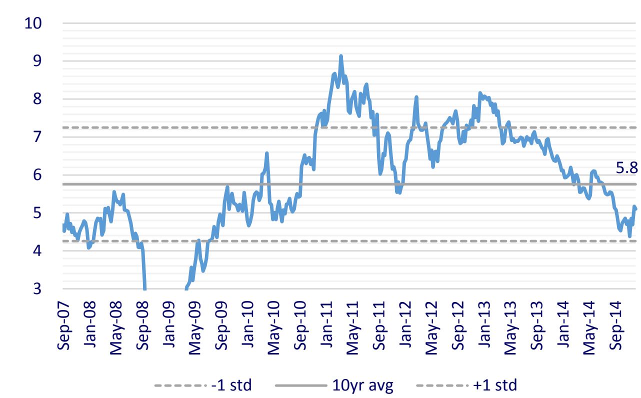
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) contract risk with its deepwater rigs, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Figure 530: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 531: The 5yr EV/EBITDA leading up to 2014

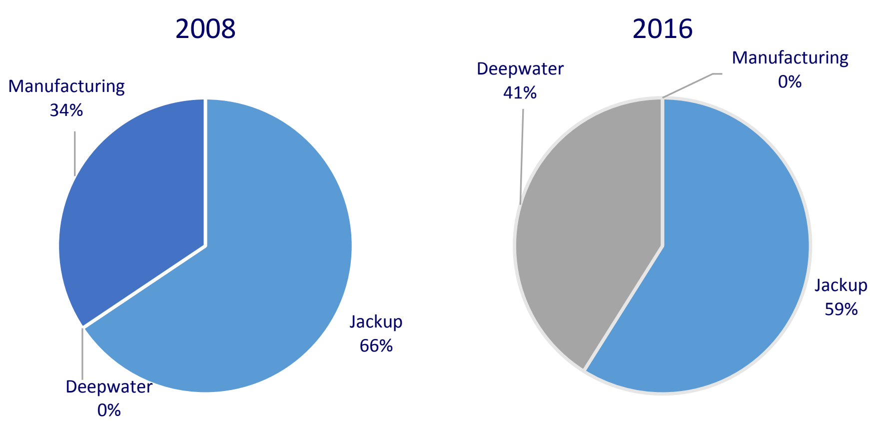


Source: Factset

Company description

Rowan Companies (RDC) is a contract drilling company with a fleet of 29 mobile offshore drilling rigs including four ultra-deepwater drillships and 25 jackups. The company is principally known as a leader in the high-specification jackup market, but made its debut in the ultra-deepwater market in 2014 with the first of four high-specification drillships. The company also recently formed a 50/50 joint venture with Saudi Aramco that will over a period of ten years add 20 newbuild jackups with 15 year term commitments each in Saudi Arabia.

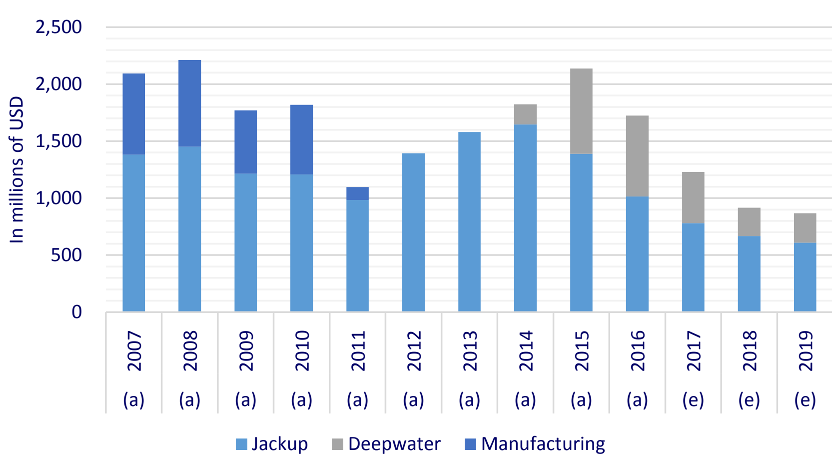
Figure 532: Revenues by rig type



Source: Company reports, Deutsche Bank

High-specification jackups are defined as jackups with at least 2.0 million lbs. of hook look capacity. Rowan owns 19 of the 73 industry-wide, excluding the 50 or so that are currently on order or under construction.

Figure 533: Change in fleet size and mix



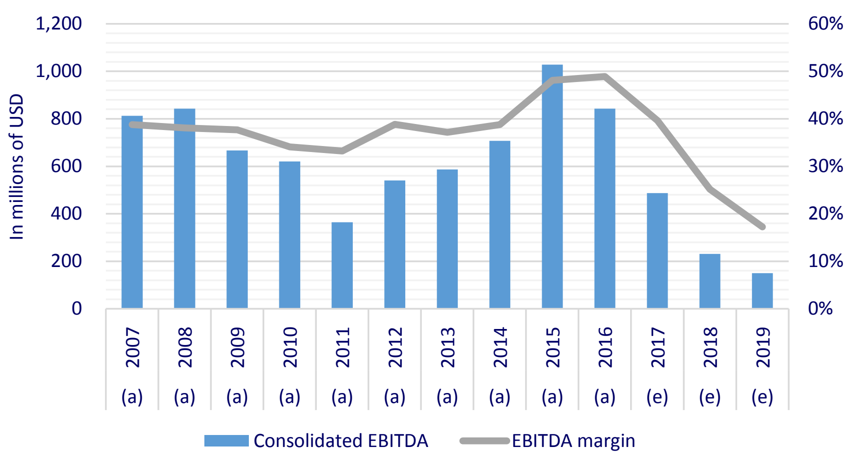
Source: Company reports, Deutsche Bank

Principal Sources and Uses of Cash Flow

Jackups only partially offsetting deepwater expirations and terminations

Ultra-deepwater revenues are on a path to zero in 2019 with terminations and contract expirations already taking the days committed in 2018 to only 17%. Ultra-deepwater EBITDA reached an annual run rate of $660 million in 2Q16, becoming a meaningful source of cash flow before the company began receiving early terminations. Looking ahead, with ultra-deepwater dayrates trafficking near $170 kpd, we expect the vast majority of the cash flow to come from the company's jackup fleet, which is operating at about 72% utilization thanks mainly to Saudi Aramco. Saudi Aramco is about 69% of Rowan's contracted backlog in jackups.

Figure 534: EBITDA



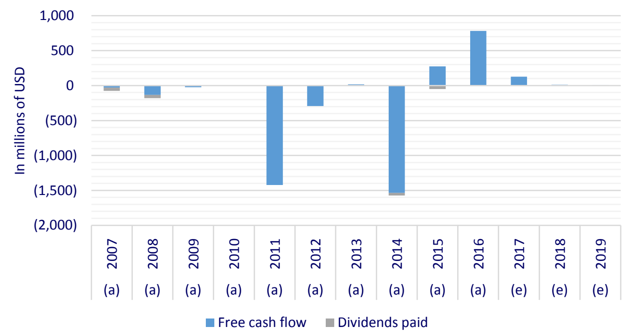
Source: Deutsche Bank

Rowan's EBITDA reached its high water mark of $1.0 billion in 2015. The four drillships contributed about 40% of that. We expect EBITDA to wind down to about $0.2 billion in 2018 assuming no new contracts for any of its four drillships. If the company were to successfully contract any of its four drillships at market rates, the contribution would be less than $20 million per year.

Saudi Aramco JV

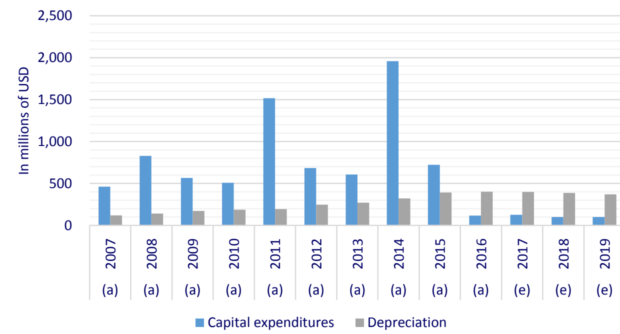
Rowan and Saudi Aramco have entered into a 50/50 JV that will own and operate upwards of 27 jackups including 20 newbuilds. Each will contribute $25 million with the JV commencing in 2Q17. Rowan will also contribute three of its jackups including the Gilbert Rowe, Bob Keller and J.P. Bussell, while Saudi Aramco will contribute two jackups. No earlier than October 2018, Rowan will add another two jackups, the Scooter Yeargain and the Hank Boswell. Saudi Aramco will contribute an equal amount in cash. Then the JV will begin its newbuild strategy with 15 year term commitments at undisclosed index rates that will generate a return commensurate with the risk. We expect the EBITDA per rig to range from $20-30 million, but probably at the lower-end of the range. The benefits of the newbuilds will not begin prior to 2020.

Figure 535: Free cash flow and dividends



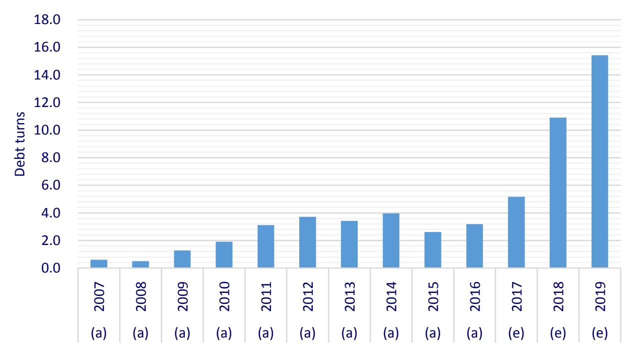
Source: Company reports, Deutsche Bank

Figure 536: Capex trend



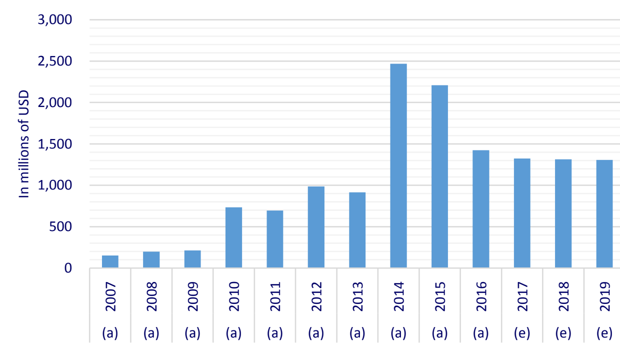
Source: Company reports, Deutsche Bank

Figure 537: Debt turns



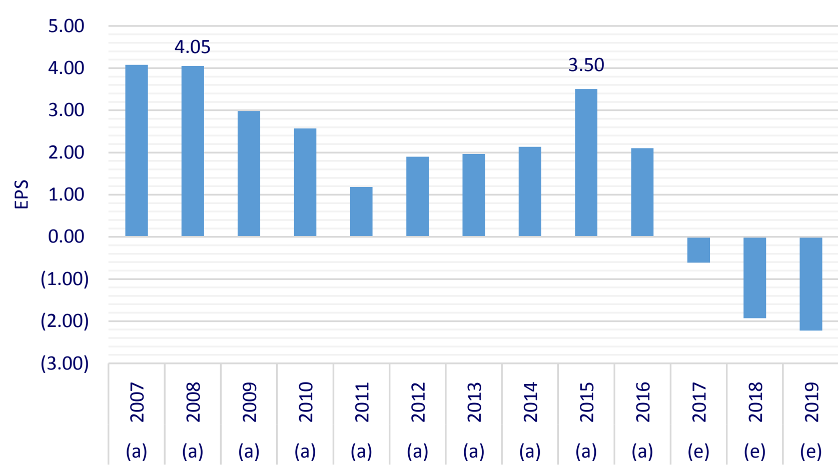
Source: Company reports, Deutsche Bank

Figure 538: Net debt



Source: Company reports, Deutsche Bank

Figure 539: EPS trend



Source: Company reports, Deutsche Bank

Figure 540: Fleet profile

Rig name	Water	Rig type	Year in	Rig design	Backlog	Backlog
Ultra-deepwater (4):						
Rowan Renaissance	12,000	DS-DP	2014	GustoMSC P10000	-	-
Rowan Resolute	12,000	DS-DP	2014	GustoMSC P10000	0.9	190.0
Rowan Reliance	12,000	DS-DP	2014	GustoMSC P10000	0.4	43.4
Rowan Relentless	12,000	DS-DP	2015	GustoMSC P10000	-	-
Jackups (25):						
Rowan Norway	430	IC	2011	Keppel FELS KFELS N Class	0.1	1.9
Rowan Stavanger	430	IC	2011	Keppel FELS KFELS N Class	0.6	39.8
Rowan Viking	430	IC	2010	Keppel FELS KFELS N Class	1.0	91.6
Rowan EXL IV	350	IC	2011	LeTourneau Super 116E EXL	-	-
Rowan EXL III	350	IC	2010	LeTourneau Super 116E EXL	-	-
Rowan EXL II	350	IC	2010	LeTourneau Super 116E EXL	0.1	4.9
Rowan EXL I	350	IC	2010	LeTourneau Super 116E EXL	-	-
Joe Douglas	400	IC	2011	LeTourneau 240-C Workhorse Class	0.0	1.2
Ralph Coffman	400	IC	2009	LeTourneau 240-C Workhorse Class	0.3	10.4
Rowan Mississippi	375	IC	2008	LeTourneau 240-C Workhorse Class	1.3	91.5
J.P. Bussell	300	IC	2008	LeTourneau 225-C Tarzan Class	-	-
Hank Boswell	300	IC	2006	LeTourneau 225-C Tarzan Class	1.1	66.5
Bob Keller	300	IC	2005	LeTourneau 225-C Tarzan Class	6.7	293.6
Scooter Yeargain	300	IC	2004	LeTourneau 225-C Tarzan Class	1.1	66.5
Bob Palmer	550	IC	2003	LeTourneau 224-C Super Gorilla XL Class	-	-
Rowan Gorilla VII	450	IC	2002	LeTourneau 219-C Super Gorilla Class	-	-
Rowan Gorilla VI	400	IC	2000	LeTourneau 219-C Super Gorilla Class	0.5	45.4
Rowan Gorilla V	400	IC	1998	LeTourneau 219-C Super Gorilla Class	2.0	69.1
Rowan Gorilla IV	450	IC	1986	LeTourneau 150-88-C Gorilla Class	0.1	2.7
Rowan California	300	IC	1983	LeTourneau Class 116-C	-	-
Cecil Provine	300	IC	1982	LeTourneau Class 116-C	-	-
Gilbert Rowe	350	IC	1981	LeTourneau Class 116-C	-	-
Arch Rowan	350	IC	1981	LeTourneau Class 116-C	1.0	26.0
Charles Rowan	350	IC	1981	LeTourneau Class 116-C	1.0	26.0
Rowan Middletown	350	IC	1980	LeTourneau Class 116-C	1.0	26.0

Source: Company reports, Deutsche Bank

Figure 541: Income Statement

In millions of USD	(a) 2009	(a) 2010	(a) 2011	(a) 2012	(a) 2013	(a) 2014	(a) 2015	(a) 2016	(e) 2017	(e) 2018	(e) 2019
Segment revenues:											
Jackup	1,215	1,209	983	1,393	1,579	1,647	1,389	1,016	782	666	609
Deepwater	0	0	0	0	0	178	748	708	447	250	259
Manufacturing	555	610	114	0	0	0	0	0	0	0	0
Total revenue	1,770	1,819	1,098	1,393	1,579	1,824	2,137	1,723	1,229	917	868
Op costs	1,001	1,066	632	752	861	991	993	778	645	590	622
SG&A	103	133	101	100	131	126	116	102	97	96	96
D&A	171	187	195	248	271	323	391	403	400	387	371
EBIT	495	434	170	293	316	385	637	440	87	(156)	(221)
Interest (expense)	(30)	(65)	(75)	(82)	(118)	(161)	(164)	(157)	(156)	(156)	(147)
Interest income	1	2	1	1	2	1	1	3	12	13	13
Capitalized interest	21	40	55	31	49	58	16	0	0	0	0
Other income	7	6	1	1	0	2	(8)	(15)	9	35	46
PBT	495	416	152	243	249	284	482	270	(49)	(264)	(309)
Income tax (expense)	(157)	(111)	(2)	(8)	(4)	(18)	(43)	(5)	(27)	21	25
Non-controlling interest	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	339	306	149	236	245	266	439	265	(76)	(243)	(285)
Discontinued ops	0	0	596	(23)	0	4	0	0	0	0	0
Unusual after-tax	29	(25)	(8)	(32)	10	(406)	(346)	55	2	0	0
Net income (GAAP)	368	280	737	181	254	(136)	93	320	(74)	(243)	(285)
Operating EPS	2.98	2.57	1.18	1.90	1.96	2.13	3.50	2.10	(0.61)	(1.93)	(2.23)
GAAP EPS	3.23	2.36	5.82	1.46	2.04	(1.09)	0.75	2.54	(0.59)	(1.93)	(2.23)
DPS	0.00	0.00	0.00	0.00	0.00	0.30	0.40	0.00	0.00	0.00	0.00
Diluted shares	114	119	127	124	124	125	125	126	127	126	128
Consolidated EBITDA	667	620	365	541	587	707	1,028	843	487	231	150
EBITDA margin	37.7%	34.1%	33.2%	38.8%	37.2%	38.8%	48.1%	48.9%	39.6%	25.2%	17.2%
EBIT margin	28.0%	23.8%	15.5%	21.0%	20.0%	21.1%	29.8%	25.5%	7.1%	-17.1%	-25.5%
Tax rate	32%	27%	2%	3%	2%	6%	9%	2%	-56%	8%	8%

Source: Deutsche Bank

Figure 542: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	339	306	149	236	245	266	439	265	(76)	(243)	(285)
Depreciation	171	187	195	248	271	323	391	403	400	387	371
Deferred tax	16	45	(21)	(5)	(34)	(183)	(1)	(38)	36	0	0
Chg in receivables	147	(34)	23	(106)	31	(201)	135	109	44	76	(36)
Chg in inventories	92	65	(104)	0	0	0	0	0	0	0	0
Chg in payables	(135)	(35)	45	(9)	32	(21)	23	(4)	(9)	(6)	9
Other	(87)	(25)	(191)	29	78	238	10	165	(140)	(105)	49
Cash from operations	544	508	95	394	623	423	997	901	256	110	108
Capital expenditures	(566)	(508)	(1,518)	(685)	(607)	(1,958)	(723)	(118)	(127)	(100)	(100)
Free cash flow	(22)	(0)	(1,423)	(292)	16	(1,535)	274	783	129	10	8
Acquisitions	0	0	0	0	0	0	0	0	0	0	0
Asset sales	9	3	1,561	11	45	22	19	6	1	0	0
Dividends paid	0	0	0	0	0	(38)	(51)	0	0	0	0
ESPP | options	1	8	20	1	7	5	0	0	0	0	0
Equity issuance, net	0	0	(125)	0	0	0	0	0	(4)	0	0
Debt issuance, net	427	(198)	(52)	866	0	793	(98)	(12)	(163)	0	(207)
Other	3	0	5	(1)	2	(1)	0	(6)	(25)	0	0
Chg in cash	417	(187)	(14)	585	69	(754)	145	771	(63)	10	(199)
FCF per share	(0.20)	(0.00)	(11.25)	(2.35)	0.13	(12.31)	2.19	6.21	1.02	0.08	0.07
Capex / revenue	0.32	0.28	1.38	0.49	0.38	1.07	0.34	0.07	0.10	0.11	0.12
Capex / depreciation	3.30	2.72	7.78	2.77	2.24	6.07	1.85	0.29	0.32	0.26	0.27

Source: Deutsche Bank

Figure 543: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	640	453	439	1,024	1,093	339	484	1,256	1,193	1,203	1,004
Accounts receivable	344	418	284	424	345	545	411	301	251	175	210
Inventories	452	348	0	0	0	0	0	0	0	0	0
Deferred taxes	38	37	27	27	22	29	0	0	0	0	0
Other current assets	77	69	72	78	69	27	27	24	24	17	20
Total current assets	1,550	1,325	822	1,553	1,529	941	921	1,580	1,468	1,394	1,235
Net PP&E	3,579	4,793	5,679	6,072	6,386	7,432	7,406	7,060	6,772	6,484	6,213
Goodwill	0	0	0	0	0	0	0	0	0	0	0
Other assets	81	99	97	75	61	38	20	35	57	40	48
Total assets	5,211	6,217	6,598	7,699	7,976	8,411	8,347	8,676	8,297	7,918	7,496
Accounts payable	125	117	111	83	124	103	110	94	78	72	81
Accrued expenses	0	0	131	121	156	194	186	159	110	77	93
Deferred revenue	139	153	36	52	55	36	33	104	61	42	51
Current debt	65	52	45	0	0	0	0	127	0	207	0
Other current liabilities	239	207	25	38	20	0	0	0	0	0	0
Total current liabilities	568	529	348	294	355	333	329	484	249	399	225
Long-term debt	787	1,134	1,089	2,010	2,009	2,807	2,692	2,553	2,517	2,309	2,309
Deferred taxes	466	551	476	474	430	211	196	186	22	22	22
Employee obligations	0	0	0	0	0	0	0	0	0	0	0
Other LT liabilities	279	251	358	390	289	368	358	339	253	176	212
Non-controlling int	0	0	0	0	0	0	0	0	0	0	0
Shareholders' equity	3,110	3,752	4,326	4,532	4,894	4,691	4,772	5,114	5,255	5,011	4,727
Total liabilities and equity	5,211	6,217	6,598	7,699	7,976	8,411	8,347	8,676	8,297	7,918	7,496
Total debt	852	1,186	1,134	2,010	2,009	2,807	2,692	2,680	2,517	2,517	2,309
Net debt	213	733	696	986	916	2,468	2,208	1,425	1,324	1,314	1,305
Debt/capital	22%	24%	21%	31%	29%	37%	36%	34%	32%	33%	33%
Debt/equity	27%	32%	26%	44%	41%	60%	56%	52%	48%	50%	49%
Debt turns	**1.3**	**1.9**	**3.1**	**3.7**	**3.4**	**4.0**	**2.6**	**3.2**	**5.2**	**10.9**	**15.4**

Source: Deutsche Bank

Rating
Hold

North America
United States

Industrials
Oil Services & Equipment

Company
RPC Inc

Reuters	Bloomberg
RES.N	RES US

David Havens
Research Analyst
+1-212-250-3235
david.havens@db.com

Price at 5 Oct 2017 (USD)	23.98
Price target	25.00
52-week range	24.79 - 16.66

Strong Leverage with Strong Buy-in Already

Initiating coverage with a Hold rating and $25 price target

RES has been the go to stock in the mid-cap services universe due its high operating leverage to the positive fundamentals in the US pressure pumping market, its debt-free balance sheet, and strong free cash flow track record. Typically a name we would want to be adding exposure to, but the idea is well known, well liked, and already well on its way. Given our view that the US will encounter a flattened rig count in 2018, we are initiating with a Hold and a $25 price target.

Industry trends favoring frac above all else

The frac market is one of the very few that is actually seeing scarcity value. The US market has recovered to about 12 million active horsepower versus 6 million at the trough and 17 million at the 2014 peak. Pricing is being restored, but at a more moderate pace than what many producers had suggested earlier in the year. We expect pricing to move higher, and for newbuilds to pick up momentum. Offsetting the risk of newbuilds is an accelerating attrition rate upwards of 3.5 million hhp and a market that is already about 1.5 – 2.0 million hhp undersupplied by some contractor estimates.

RES's frac fleet is 95% manned and fully booked through year-end

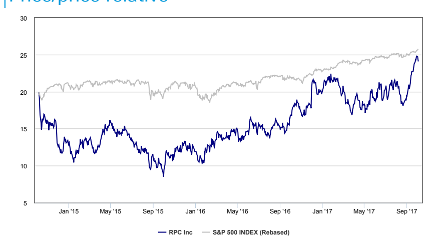
All of RES's fleet is in the spot market as the company expects to achieve higher pricing into 2018. Earnings revisions for 2018 have been up and to the right as investors have focused intensely on this name. We think a step change in pricing is needed to take the next leg higher.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.15	0.02A	0.35
2Q EPS	-0.23	0.20A	0.35
3Q EPS	-0.18	0.28	0.36
4Q EPS	-0.10	0.33	0.36
FY EPS (USD)	-0.66	0.83	1.42
OLD FY EPS (USD)	–	–	–
% Change	–	–	–
P/E (x)	–	28.7	16.9
DPS (USD)	0.05	0.12	0.24
Dividend Yield (%)	0.3	0.5	1.0
Revenue (USDm)	729.0	1,660.6	2,091.8

Source: Deutsche Bank estimates, company data

Price/price relative



Performance (%)	1m	3m	12m
Absolute	24.4	15.7	44.1
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	5,217.5
Shares outstanding (m)	217.6
Free float (%)	–
Volume (5 Oct 2017)	392,263
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Valuation

Our $25 price target is 7.3x our estimate of the company's normalized EBITDA power of $700 million, is a 1.5 turn premium to the 5.8x five-year average multiple leading up to the 2014 collapse in oil prices. The company has no leverage, generates solid free cash flow, and is likely to grow its frac capacity and its normalized EBITDA above our current range.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a swift increase in new frac capacity in the US, and 4) and a subsequent move lower in pricing and margins.

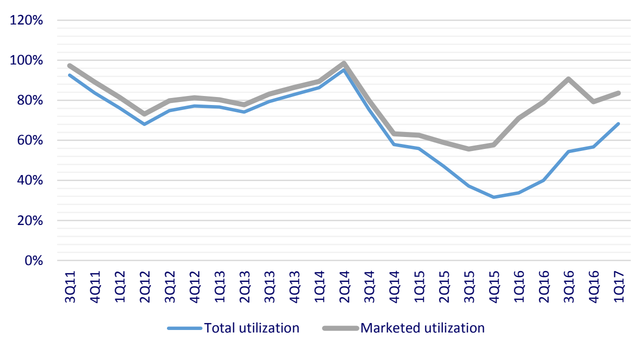
Key investment themes

US pressure pumping market is undersupplied

The positive supply/demand trends are continuing in the frac market, driven by a rising well count, increased pad drilling, more wells per pad and an increasing inventory of DUCs (drilled but uncompleted wells). Frac fleets are also incorporating more hhp, averaging about 50k now. The increase is to accommodate the larger pads, which are keeping crews on location longer, thus in order to accommodate maintenance rotations and suitable uptime, contractors have increased fleet sizes.

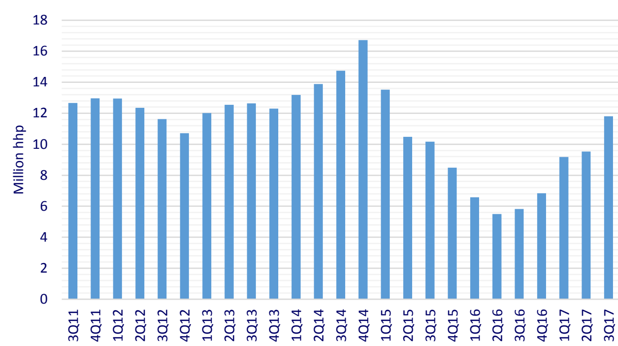
RES has been reactivating idle equipment throughout the year as demand industry-wide has recovered to about 12 million hhp versus 17 million at the peak, and less than 6 million at the trough. All available horsepower by and large is now booked through year-end 2017. Marketed utilization is back above 80% with some contractors suggesting the market is undersupplied by 1.5 – 2.0 million horsepower. RES sees demand exceeding supply and has said its fleet is booked through year-end as well. The company had only 50% of its fleet manned in 4Q16, 70% in 1Q17, 80% in 2Q17, and expects to be at 95% in 3Q17 with half of its hhp in the Permian and two crews in the Bakken. With its fleet near full utilization, we expect incremental margins to drive EPS in 2H17.

Figure 544: Total vs. marketed frac hhp utilization



Source: IHS Markit, Deutsche Bank

Figure 545: US frac hhp demand

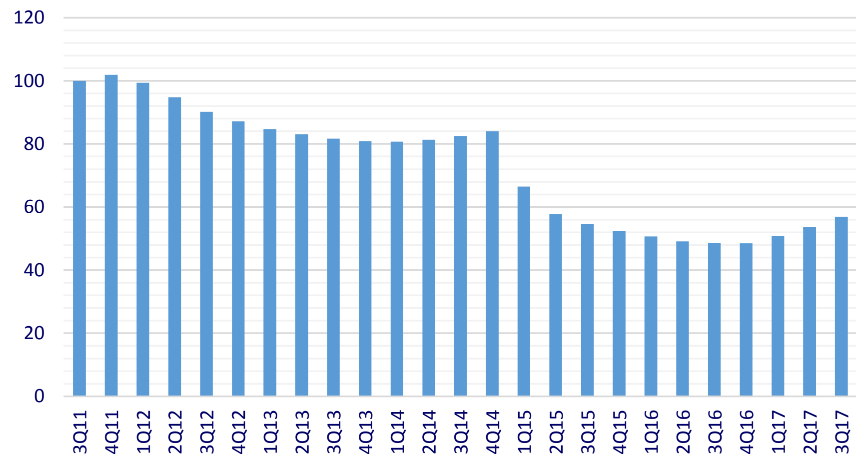


Source: IHS Markit, Deutsche Bank

Pricing moving higher, albeit more modestly

All of RES's frac horsepower is in the spot market right now. Management sees opportunity for pricing to move higher, although we understand there has been some operator push back (as there typically is). Pricing has improved, but more moderately than what some producers had previously expected. While several contractors are suggesting pricing is not yet at newbuild economics, newbuilds are coming, including about 100k hhp from RES. RES is not booking term now because if oil prices move lower, customers would look to renegotiate contracts anyway, thus worth waiting for the upside in spot prices.

Figure 546: US frac pricing indexed to 3Q11



Source: IHS Markit, Deutsche Bank

Attrition is increasing

Frac intensity on the larger pads and bigger wells is chewing equipment faster than last cycle, kicking attrition into a higher gear. Industry expectations for attrition are upwards of 3.5 million hhp per annum as useful lives decline and maintenance capital rises. While this is tightening the market upfront, it increases the capital intensity for the industry longer term.

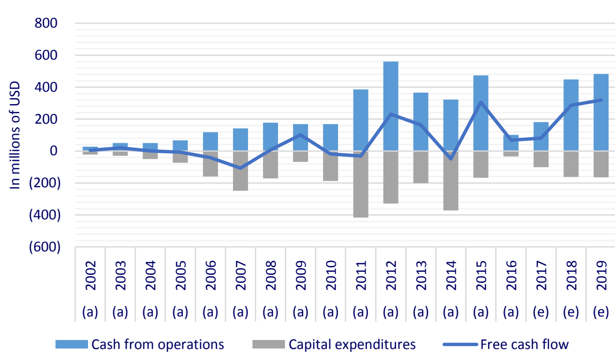
Modest newbuilding, but likely to pickup

Newbuild lead times for frac spreads are about 9-12 months versus a high of 18 months last cycle. Newbuild costs are back up to $1,000/hhp with modest activity underway. RES intends to order 100k hhp for $1,000/hhp for early 2018 delivery, but half will replace older equipment.

RES has a clean balance sheet and should generate solid free cash flow

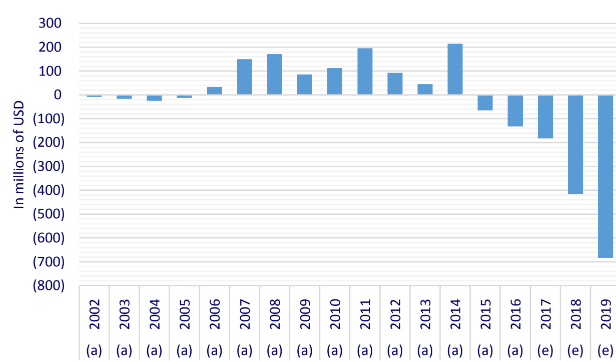
RES has no debt and is among the industry leaders in terms of generating free cash flow.

Figure 547: Strong free cash flow



Source: Company reports, Deutsche Bank

Figure 548: No debt



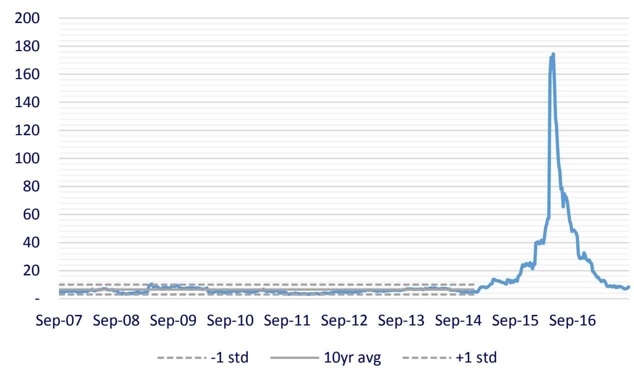
Source: Company reports, Deutsche Bank

Valuation and risks

Our $25 price target is 7.3x our estimate of the company's normalized EBITDA power of $700 million, is a 1.5 turn premium to the 5.8x five-year average multiple leading up to the 2014 collapse in oil prices. The company has no leverage, generates solid free cash flow, and is likely to grow its frac capacity and its normalized EBITDA above our current range.

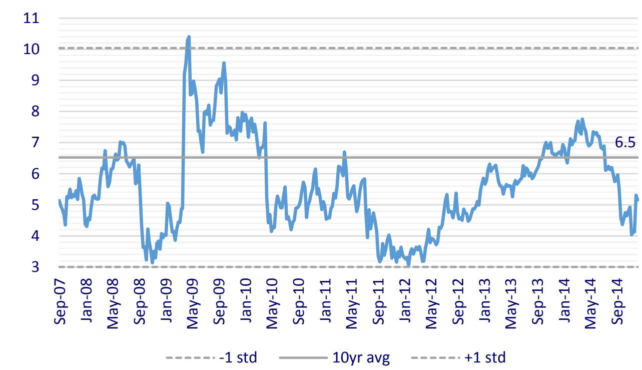
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a swift increase in new frac capacity in the US, and 4) and a subsequent move lower in pricing and margins.

Figure 549: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 550: The 5yr EV/EBITDA leading up to 2014



Source: Factset

Company description

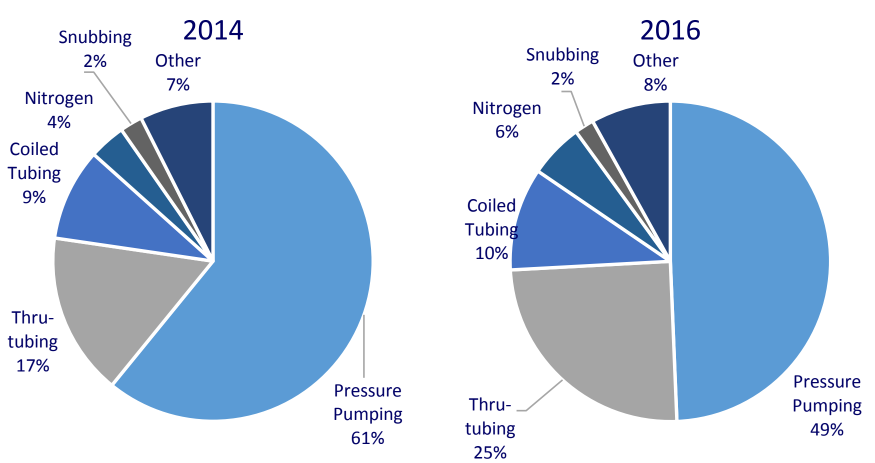
RPC Inc. (RES) was founded in 1984 and operates today as a holding company for the oilfield services operating units of Cudd Energy Services, Thru Tubing Solutions and Services with 3,000 employees. The structure was created via Rollins Inc.'s decision to spin off and Cudd Pressure Control (CPC) under the name RPC Energy Services. In 1996 RPC Energy Services was renamed RPC Inc. and in 2000 expanded into pressure pumping. Today RPC provides a range of services to E&P's throughout the United States (accounting for 93% of 2016 revenues) in the Southwest, Mid-Continent, Gulf of Mexico, Rocky Mountains and Appalachia regions. International markets were 7% of 2016 revenues and 6% in 2015.

Figure 551: Reporting segments

RPC, Inc.	
Technical Services - Pressure Pumping - Thru Tubing Solutions - Coiled Tubing - Nitrogen - Snubbing	**Support Services** - Rental Tools - Tubular Services

Source: Company reports, Deutsche Bank

Figure 552: Revenue mix



Source: Company reports

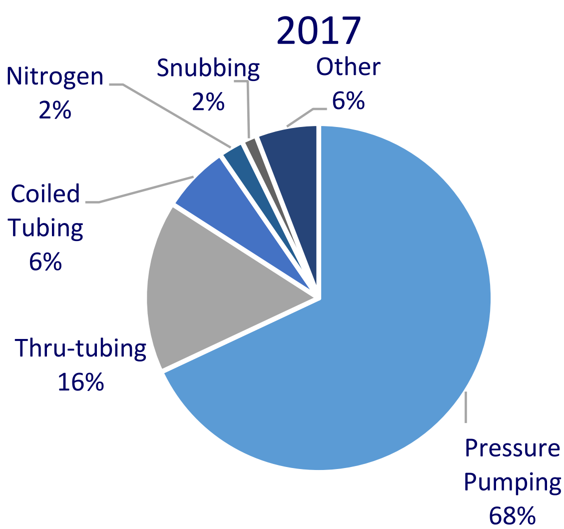
RPC has two reporting segments, Technical Services and Support Services. Technical Services includes pressure pumping, thru-tubing, coiled tubing, nitrogen services, snubbing, well control, wireline and fishing services. Support Services includes Rental Tools and Tubular Services, which provides tubular inspections.

Principal Sources and Uses of Cash Flow

Pressure pumping is its core business and the US is its principal market

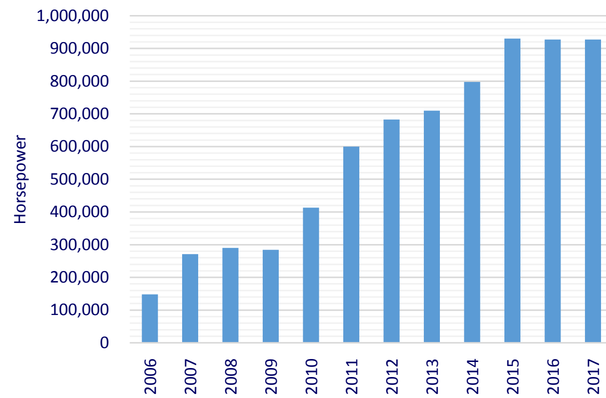
RES generates about two-thirds of its revenues from pressure pumping and rising. The company has added almost 800k hhp since 2006. The company's principal markets are the Permian, Mid-Continent, Rocky Mountains, and Appalachia. In the last 3 years services, a small slice of services have also been provided in the Gulf of Mexico, Canada, Latin America and the Middle East.

Figure 553: RES revenue mix (2017 DBe)



Source: Company reports, Deutsche Bank

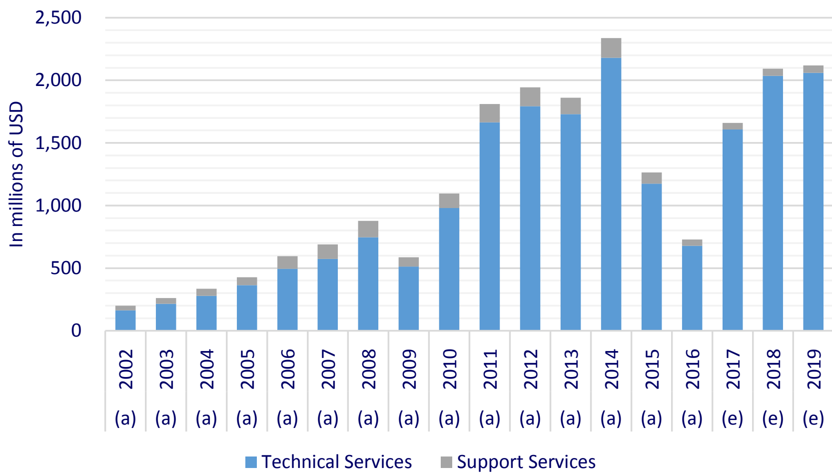
Figure 554: RES pressure pumping horsepower



Source: Company reports, Deutsche Bank

In 2016, 70% of RPC revenues were from drilling and production activities for oil and 30% from natural gas. Less than 1% were from offshore operations in the Gulf of Mexico. It had positive free cash flow of $68mn in 2018 (down from $306mn in 2015), partially influenced by the lowest capex in 10-years of $34mn. RPC began 2017 guiding to $70mn of capex, almost entirely focused toward maintenance, and recently increased to $100mn given the pace of unstacking. We expect margins to help double-digit free cash flow in 2017 driven by the US land rig count uptick, the entire pumping fleet in the spot market (booked through YE17), and remaining reactivations by 3Q with benefit in 4Q.

Figure 555: Segment revenues

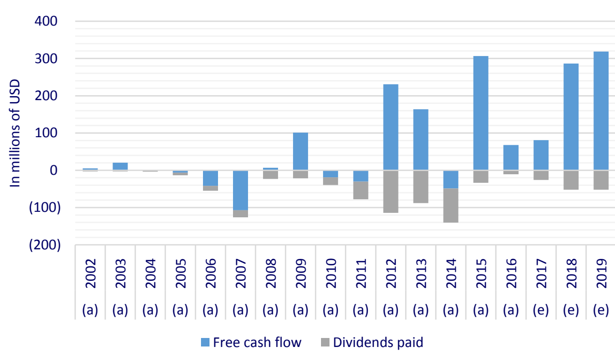


Source: Company reports, Deutsche Bank

Strong balance sheet, no debt and an undrawn revolver

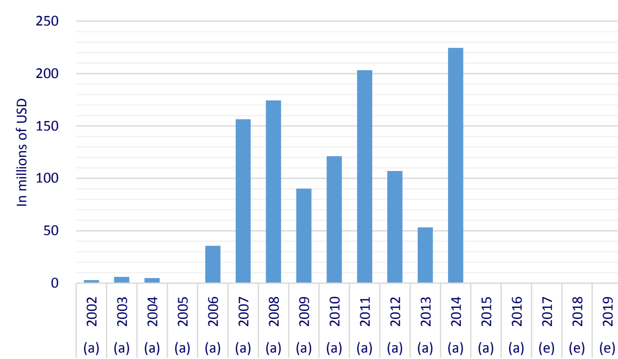
RPC has operated a conservative balance sheet (maximum 0.9 debt turns in 2009) and has not carried debt since 2014. At 2Q it had $125mn of cash with an undrawn $125mn revolving credit facility. The $0.05/share dividend was suspended in July 2015, with a special dividend of $0.05/share paid 4Q16 and a $0.06/share dividend paid 3Q17. Management was (as expected) cautious in calling the recent payment a regular dividend. The company's stock buyback plan in place since 1998, and without expiry date, remains active with 1.7mn of the original 31.5mn shares available for repurchase as of 2Q.

Figure 556: RES free cash flow and dividends



Source: Company data, Deutsche Bank

Figure 557: RES total debt



Source: Company data, Deutsche Bank

Figure 558: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Technical Services	513	980	1,664	1,794	1,730	2,180	1,175	680	1,607	2,036	2,060
Support Services	75	117	146	151	132	157	89	49	53	56	58
Other	0	0	0	0	0	0	0	0	0	0	0
Total revenues	588	1,096	1,810	1,945	1,861	2,337	1,264	729	1,661	2,092	2,118
Segment EBIT:											
Technical Services	(20)	217	451	420	276	390	(133)	(204)	299	495	517
Support Services	(2)	31	52	46	26	43	(2)	(26)	(13)	(5)	2
Corporate	(12)	(13)	(17)	(18)	(18)	(17)	(13)	(17)	(17)	(17)	(17)
EBIT	(34)	235	486	448	285	415	(149)	(247)	269	473	502
Interest (expense)	(2)	(3)	(3)	(2)	(2)	(1)	(2)	(1)	(0)	(0)	(0)
Interest income	0	0	0	0	0	0	0	0	1	0	0
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	3	5	(4)	(4)	(7)	(15)	(2)	8	14	15	15
PBT	(33)	238	479	443	276	399	(153)	(239)	283	487	516
Income tax (expense)	11	(91)	(182)	(168)	(109)	(154)	53	98	(102)	(179)	(190)
Non-controlling interest	0	0	0	0	0	0	0	0	0	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	(23)	147	296	274	167	245	(100)	(141)	182	308	326
Discontinued ops	0	0	0	0	0	0	0	0	0	0	0
Unusual after-tax	0	0	0	0	0	0	0	0	0	0	0
Net income (GAAP)	**(23)**	**147**	**296**	**274**	**167**	**245**	**(100)**	**(141)**	**182**	**308**	**326**
Operating EPS	**(0.10)**	**0.67**	**1.35**	**1.27**	**0.77**	**1.14**	**(0.47)**	**(0.66)**	**0.83**	**1.42**	**1.50**
GAAP EPS	(0.10)	0.67	1.35	1.27	0.77	1.14	(0.47)	(0.66)	0.83	1.42	1.50
DPS	0.10	0.09	0.21	0.32	0.40	0.42	0.16	0.05	0.12	0.24	0.24
Diluted shares	217	220	220	217	217	216	213	214	218	218	218
Consolidated EBITDA	96	368	666	663	498	646	122	(30)	433	628	660
EBITDA margin	16.4%	33.6%	36.8%	34.1%	26.7%	27.6%	9.7%	-4.1%	26.1%	30.0%	31.1%
EBIT margin	-5.8%	21.4%	26.8%	23.1%	15.3%	17.8%	-11.8%	-33.9%	16.2%	22.6%	23.7%
Tax rate	32.1%	38.2%	38.1%	38.0%	39.6%	38.6%	34.9%	41.0%	35.9%	36.7%	36.7%
EBIT margin											
Contract Drilling	(4.0%)	22.2%	27.1%	23.4%	16.0%	17.9%	(11.3%)	(30.0%)	18.6%	24.3%	25.1%
Pressure Pumping	-2.2%	26.7%	35.4%	30.4%	19.9%	27.1%	-2.7%	-52.8%	-25.3%	-8.7%	3.7%

Source: Deutsche Bank

Figure 559: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	(23)	147	296	274	167	245	(100)	(141)	182	308	326
Depreciation	131	133	180	215	213	231	271	217	164	155	158
Deferred tax	2	22	77	5	(13)	12	(33)	(34)	(21)	0	0
Chg in receivables	80	(163)	(167)	74	(50)	(198)	402	65	(259)	(20)	(2)
Chg in inventories	(6)	(8)	(37)	(40)	14	(30)	27	20	(28)	(6)	3
Chg in payables	(6)	14	30	(5)	14	36	(62)	(6)	50	5	(3)
Other	(9)	23	6	37	20	26	(31)	(19)	94	6	1
Cash from operations	169	169	386	560	366	323	474	102	181	449	483
Capital expenditures	(68)	(187)	(416)	(329)	(202)	(372)	(167)	(34)	(101)	(162)	(164)
Free cash flow	101	(19)	(30)	231	164	(49)	306	68	81	287	319
Acquisitions	0	0	0	0	(17)	0	0	0	0	0	0
Asset sales	7	16	25	19	11	19	10	13	8	0	0
Dividends paid	(22)	(21)	(47)	(114)	(88)	(92)	(34)	(11)	(26)	(52)	(52)
ESPP | options	0	0	0	0	0	0	0	0	0	0	0
Equity issuance, net	(2)	(2)	(34)	(30)	(25)	(50)	(4)	(3)	(12)	0	0
Debt issuance, net	(84)	31	82	(96)	(54)	171	(225)	0	0	0	0
Other	1	(1)	4	(3)	3	1	1	0	0	0	0
Chg in cash	1	5	(2)	7	(5)	1	55	67	51	234	267
FCF per share	0.47	(0.09)	(0.14)	1.07	0.76	(0.23)	1.44	0.32	0.37	1.32	1.47
Capex / revenue	0.12	0.17	0.23	0.17	0.11	0.16	0.13	0.05	0.06	0.08	0.08
Capex / depreciation	0.52	1.41	2.31	1.53	0.95	1.61	0.62	0.16	0.61	1.04	1.04

Source: Deutsche Bank

Figure 560: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	4	9	7	14	9	10	65	132	182	417	684
Accounts receivable	131	294	461	388	437	635	232	169	428	449	451
Inventories	56	64	100	141	127	156	128	108	137	142	140
Other current assets	29	32	57	25	32	52	66	70	25	26	26
Total current assets	219	399	627	568	605	852	492	479	772	1,034	1,300
Net PP&E	396	453	675	756	726	849	688	498	436	442	449
Goodwill	24	24	24	24	32	32	32	32	32	32	32
Other assets	9	12	12	19	21	26	24	26	36	38	38
Total assets	649	888	1,338	1,367	1,384	1,759	1,237	1,035	1,276	1,546	1,819
Accounts payable	50	79	123	110	119	175	76	71	126	131	129
Current debt	0	0	0	0	0	0	0	0	0	0	0
Other current liabilities	18	39	46	55	49	64	32	31	56	59	59
Total current liabilities	68	118	169	165	168	239	107	101	182	190	188
Long-term debt	90	121	203	107	53	225	0	0	0	0	0
Other LT liabilities	149	228	362	324	330	412	285	229	320	334	333
Shareholders' equity	410	539	773	936	1,001	1,123	952	807	956	1,212	1,486
Total liabilities and equity	649	888	1,338	1,367	1,384	1,759	1,237	1,035	1,276	1,546	1,819
Total debt	90	121	203	107	53	225	0	0	0	0	0
Net debt	86	112	196	93	45	215	(65)	(132)	(182)	(417)	(684)
Debt/capital	18%	18%	21%	10%	5%	17%	0%	0%	0%	0%	0%
Debt/equity	22%	22%	26%	11%	5%	20%	0%	0%	0%	0%	0%
Debt turns	**0.9**	**0.3**	**0.3**	**0.2**	**0.1**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Schlumberger

Reuters	Bloomberg
SLB.N	SLB US

David Havens
Research Analyst
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Price at 5 Oct 2017 (USD)	68.87
Price target	78.00
52-week range	87.48 - 62.88

Pore to Pipeline Products and Services

Initiating with a Buy rating and a $78 price target

In a challenging industry environment, we like companies that evolve, develop new markets and business models. While SLB does not generate the early EPS leverage of its North American peers, it has a solid track record of delivering long-term margin resiliency and expansion, especially in international markets where it has outperformed its closet peer by over 770 basis points and its other peers by 1000's of basis points. The company has an industry-leading free cash flow track record of over $30 billion the last ten years. International markets are challenged but we believe SLB will squeeze more margin from them than any of its peers. In the US, the company still has about 30% of its business there and is actively ramping up its leverage via frac reactivations and its latest JV OneStim.

Initiating with a Buy rating and a $78 price target

We believe SLB knows how to navigate sea changes in the market. While SLB is best-in-class in terms of tool reliability, service deliverability, breadth and depth of product portfolio and the art of upselling, what is setting SLB apart now is its leadership in establishing new business models that push the value of intellectual property, data analytics, automation, machine learning and Big Data.

Asset turn efficiency a core differentiator

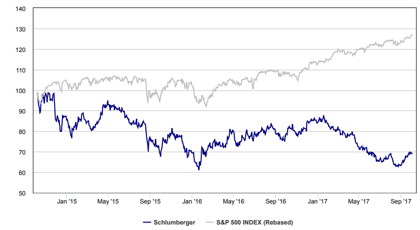
For years the company has been addressing low single-digit utilization of the industry's tools in an effort to curb working capital needs, reduce capex and increase margins. While the key industry players are fighting for a smaller upstream capex pie, SLB is also seeking profitability internally. Market share preservation can sometimes be more important for the industry, but SLB has a mechanism to preserve margins and even grow them in challenging environments. We believe SLB's asset turn efforts enables earnings upside to an otherwise competitive international market.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.40	0.25A	0.51
2Q EPS	0.23	0.35	0.54
3Q EPS	0.25	0.41	0.64
4Q EPS	0.27	0.46	0.69
FY EPS (USD)	1.14	1.47	2.38
OLD FY EPS (USD)	1.13	–	–
% Change	0.5%	–	–
P/E (x)	67.7	46.9	28.9
DPS (USD)	2.00	2.00	2.45
Dividend Yield (%)	2.6	2.9	3.6
Revenue (USDm)	27,810.0	30,575.5	32,702.6

Source: Deutsche Bank estimates, company data

Price/price relative



Performance (%)	1m	3m	12m
Absolute	8.6	2.8	-12.4
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	95,781.0
Shares outstanding (m)	1,390.8
Free float (%)	100
Volume (5 Oct 2017)	1,456,619
Option volume (und. shrs., 1M avg.)	2,356,468

Source: Deutsche Bank

Valuation and risks

Our $78 price target is 18.0x our estimate of the company's normalized EPS power of $4.25 per share, which is in-line with its 18.3x five-year average multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 28x our 2018 EPS estimate of $2.43 and 20x our 2019 estimate of $3.39.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an inability to capture margin in its growing project management business, and 4) another deceleration in international spending budgets that disproportionately impacts SLB versus its more North American peers.

Key investment themes

International markets

International markets are struggling to recover even after three consecutive years of severely depressed spending. Lower oil prices and the OPEC cuts have delayed some tenders and have kept market share preservation tactics in play. The weak drive in international markets is not enough to carry earnings higher for the industry as contractors look to preserve utilization and avoid demobilization.

But this is the type of market where we believe Schlumberger delivers its value to shareholders via better than expected earnings power. While the company does not provide the hyper-leverage to US onshore margins like Halliburton does, SLB knows how to navigate sea changes in the market. This is not business as usual for the oilfield services industry. These companies need to navigate through the turbulence of the most severe downturn in 30 years. Intellectual property, data analytics, automation, machine learning and Big Data are all contributing to higher efficiencies and lower costs, and have become the differentiating factors that will decide the winners and losers. While SLB is best-in-class in terms of tool reliability, service deliverability, breadth and depth of product portfolio and the art of upselling, what is setting SLB apart now is its leadership in establishing new business models that push the value of intellectual property, data analytics, automation, machine learning and Big Data. The barrier-to-entry here is a bit different than the 9-12 month lead times for delivering a frac spread.

Asset turn efficiency a core differentiator

The company has for years been addressing the low single-digit utilization of the industry's tools in effort to curb working capital needs, reduce capex and increase margins. While the key industry players are all fighting for a smaller upstream capex pie, SLB is also seeking profitability internally. Now all of its peers have has to cut costs. But this is not just a cost cutting effort. SLB is looking to change how it does business and is looking to get a higher turn in every dollar invested without having to rely in pricing alone. Market share preservation can sometimes be more important for the industry, but SLB has a mechanism to preserve margins and even grow them in challenging environments. We believe SLB's asset turn efforts enables earnings upside to an otherwise competitive international market.

SPM is the new model needed to demonstrate growth

Many investors are weary of something they cannot see or touch, and there is limited transparency in SLB's SPM business, but it is a fundamental driver of the company's growth. SLB generated $1.4 billion in SPM revenues in 2016, which was a bit less than 5% of total revenues. From 2011 to 2016, management has said the business generated margins that were 700 basis points higher than its base business. It was also the only business that grew during the downturn. Patrick Schorn, formerly president of operations, has assumed the role of Executive Vice President of New Ventures, which means he oversees SPM. This is indicative of the prominence this model has within the company, which SLB believes will be twice the $1.4 billion in revenues going forward (timing not quantified).

Some of the investor concerns though, other than transparency and difficulty modeling, involve the returns. Over the last five-years, SLB will have capitalized over $4 billion in SPM, but it is difficult to measure what the return on this has or will be. The structure of this business is to capitalize costs and then amortize over the life of the project. Depending on SLB's performance, margins toward the tail-end of the project can benefit or dilute overall margins. While management has indicated the returns are competitive, hence why the capital is being directed there, SLB also highlighted the benefits of SPM absorbing some of the fixed costs in sub-scale regions internationally. It is providing a baseline of business and it is allowing SLB to showcase technology and establish a track record. There are apparently about 50 projects in the pipeline and 1/10 win rate for SLB. While we are unable to demonstrate the accretive nature of this business independently, SLB has consistently generated peer leading margins internationally. From 2007 to 2015, which is when geographic margins stopped being reported, SLB outperformed its closet international competitor Halliburton by 770 basis points on average.

Rig of the future

SLB's vision is to revolutionize well construction, and its Integrated Drilling System is the centerpiece with the land drilling system of the future. This combines surface and downhole hardware with optimization software that will automate the drilling process including the integration of rig systems as well as integration of downhole data for directional drilling and well placement efforts. SLB has seven rigs in process of being deployed in the US, Ecuador and Saudi Arabia. Why own the rig? Because SLB believes it is the best platform to integrate around. But SLB also needs rigs for its SPM business, and has in the past needed upwards of 100 rigs. SLB has achieved access in other ways including a JV with the Arabian Drilling Company and its efforts to acquire Eurasia Drilling. Part of the appeal with Eurasia is in Russia, rig contractors generally choose the service companies, not the operator. SLB does not plan on acquiring a US land driller, but it did acquire OMRON, which has 50% of the control systems in the North America market.

Valuation and risks

Our $78 price target is 18.0x our estimate of the company's normalized EPS power of $4.25 per share, which is in-line with its 18.3x five-year average multiple leading up to the 2014 collapse in oil prices. The company is currently trading at 28x our 2018 EPS estimate of $2.43 and 20x our 2019 estimate of $3.39.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an inability to capture margin in its growing project management business, and 4) another deceleration in international spending budgets that disproportionately impacts SLB versus its more North American peers.

Company description

Schlumberger (SLB) is the industry's largest multi-national oilfield services company with operations in over 85 countries. The company is a leading provider of technology and best practices for reservoir characterization, drilling, and production to the global oil and gas industry. Since its roots in wireline logging, SLB has pursued an integrated model capable of delivering a comprehensive range of products and services throughout the well lifecycle that optimize recovery and improve reservoir performance.

For the last eight years, SLB has been implementing a transformation program that focuses on changing the way it works. Historically SLB has focused on the subsurface, specifically on formation evaluation and reservoir characterization. The company is now looking at new ways to improve total system performance in drilling and production, where there is considerable untapped potential to be harnessed through the integration of surface and subsurface technologies. But the company has also been implanting new ways of managing its resources and optimizing asset turns in an effort to reduce working capital, capex, and increase margins.

Figure 561: Schlumberger reporting segments

Schlumberger Ltd.

Reservoir Characterization
- WesternGeco - seismic (marine and land)
- Wireline - openhole and cased hole services
- Well Testing - pressure/flow measurements
- Software Integrated Solutions (SIS)
  - Proprietary software, info management
  - Consulting, IT infrastructure
- Integrated Services Management (ISM)

Drilling Group
- Bits and drilling tools, tubular services
- M-I SWACO - fluids
  - Managed pressure drilling (MPD)
  - Underbalanced drilling solutions
- Drilling & Measurements
  - Mud logging, directional drilling (DD)
  - Measurement-while-drilling (MWD)
  - Logging-while-drilling (LWD)
- Land drilling
- Integrated Drilling Services (IDS)

Production Group
- Well Services - pressure pumping, stimulation, cementing, coiled tubing, reservoir monitoring, downhole data acquisition
- Completions - packers, sand control, valves, intelligent well technology
- Artificial Lift - ESP, gas lift, rod lift, PCPs
- Integrated Production Services
- Schlumberger Production Management (SPM)

Cameron
- OneSubsea - subsea production systems
  - Wellheads, subsea trees, control systems
  - Manifold and flowline connectors
  - Integration and optimation services
- Surface Systems - wellheads, Christmas trees
- Drilling Systems - drilling equipment
  - Pressure control equipment
  - Rotary drilling equipment
- Valves and Measurements

Source: Company reports, Deutsche Bank

SLB's vision is to revolutionize well construction, and its Integrated Drilling System is the centerpiece, or the land drilling system of the future as they call it. This system combines surface and downhole hardware with optimization software that allows for drilling systems integration, automation and eventually, machine learning.

Principal Sources and Uses of Cash Flow

SLB is organized in four groups including Reservoir Characterization, Drilling, Production, and Cameron. Its Reservoir Characterization group is focused on finding and classifying hydrocarbons and uses services such as seismic imaging, wireline, testing and processing to do so. Its Drilling group provides drill bits, downhole tools, fluid systems (M-I SWACO), drilling measurements, land rigs, directional drilling, and integrated drilling services. Its Production group is focused on reservoir production utilizing pressure pumping and other well services, completion tools, artificial lift, Integrated Project Services, and Schlumberger Production Management (a commercial arrangement where SLB receives payment in-line with its value creation). Lastly, it created its Cameron group after acquiring the company in 2016 and is mostly focused on pressure and flow control, valves, and subsea systems including its OneSubsea offering.

Reservoir Characterization

- WesternGeco – geophysical services (seismic) – reservoir imaging, monitoring and development services for both proprietary and multiclient surveys
- Wireline – openhole and cased hole services including perforating and slickline services
- Testing & Process – pressure and flow rate measurement services both at the surface and downhole – the separation of oil, gas and produced water and water injection systems – tubing conveyed perforating services
- Software Integrated Solutions (SIS) – sells proprietary software and provides consulting, information management and IT infrastructure services for reservoir characterization, field development planning, and production enhancement
- Integrated Services Management (ISM) – coordination and management of Schlumberger services, products and third parties in projects around the world – offers certified Integrated Services Project Managers as a focal point of contact between project owner and the various SLB services

Drilling

- Bits and drilling tools – drill bits, bottom-hole assembly (BHA) components, borehole enlargement technologies, tubular and tubular services
- M-I SWACO – drilling fluid systems, MPD, and underbalanced drilling solutions
- Drilling & Measurements – mud logging, directional drilling (DD), measurement-while-drilling (MWD), logging-while-drilling (LWD)
- Land Rigs – land drilling system of the future
- Integrated Drilling Services – all the services necessary for well planning, drilling, engineering, supervision, logistics, and procurement

Production

- Well Services – pressure pumping, cementing, stimulation, coiled tubing, reservoir monitoring, and downhole data acquisition

- Completions – packers, safety valves, sand control technology, intelligent well technology

- Artificial Lift – Electric submersible pumps (ESP), gas lift, rod lift, PCPs, and surface horizontal pumping systems

- Integrated Project Services – project planning, well engineering, wellsite supervision, logistics, and procurement

- Schlumberger Production Management (SPM) – A field production business model where there is commercial alignment between SLB and the operator – SLB receives payment in line with its value creation – SLB will invest its own services and products, and in some cases cash, into the field development activities and operations.

Cameron

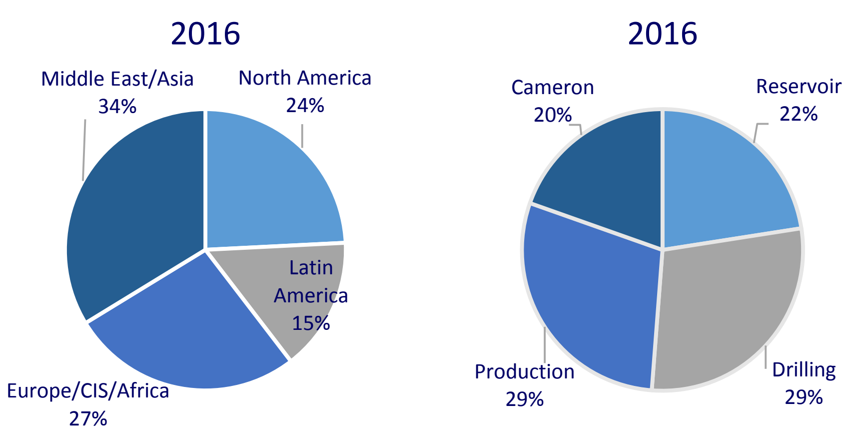
- OneSubsea – integrated subsea production systems designed to optimize production – includes wellheads, subsea trees, manifolds, flowline connectors and control systems.

- Surface Systems – wellhead systems, processing solutions, Christmas trees

- Drilling Systems – drilling equipment including pressure control equipment (BOPs), control systems, riser systems, top drives, mud pumps, pipe handling equipment and rig designs.

- Valves and Measurement – control, direct and measure the flow of oil and gas

Figure 562: Geographic and segment revenue mix



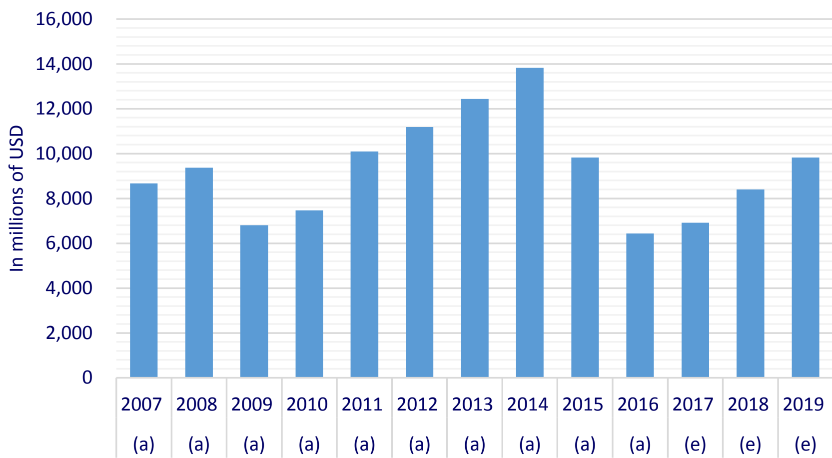
Source: Company reports, Deutsche Bank

Largest international exposure versus its peers

SLB has a larger exposure to international markets than its peers. While Halliburton in 2006 made clear to investors it was a North American centric oilfield services company, SLB had already taken a different path and was the undisputed leader in most international markets. The company did not see the merits of a price knife-fight in a large US competitive landscape , at least until conventional oil development gave way to unconventional tight oil development. Now SLB has invested more resources in North America, but is still only about 30% of total revenues as of 2Q17 and about 24% in 2016 before the US recovery got traction. US revenues 2016 were $5.4 billion, which accounted for a little over 80% of total North American revenues.

Internationally, Middle East/Asia is its largest region at 34% of 2016 revenues. Spending and activity levels in the Middle East were more resilient during the downturn than most other regions and SLB has a strong presence. In the last 10 years, the Middle East/Asia region had been closer to 25% of total revenue but since the start of 2016 has been over 30%. Europe/Africa/CIS is the next largest region accounting for 27% of 2016 revenues. Lastly, Latin America accounted for 15% in 2016.

Figure 563: Consolidated EBITDA



Source: Company data, Deutsche Bank

Evolving with new business models

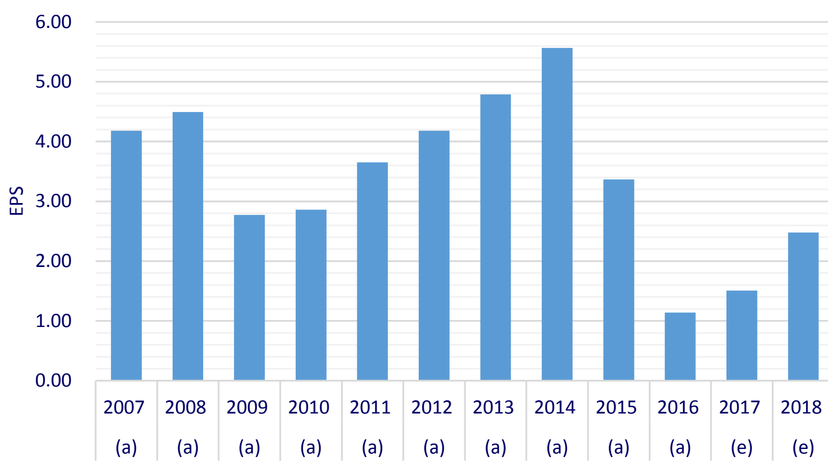
SLB's strategy has been focused on driving value for their customers through integration, efficiencies, and investment in technology. The ultimate goal is lowering the cost per barrel and increasing recovery rates for their customers. The approach is different from its peers as SLB believes the best way is through integration and fostering closer collaboration and commercial alignment with customers which ultimately will drive efficiency improvements and better leverage technological developments. There are several examples of this strategy being implemented such as their acquisition of Cameron, which combined SLB's reservoir and well technology with Cameron's wellhead and subsea expertise. Another example is its development of OneDrill which is an integrated drilling system that focuses on understanding the entire drilling workflow, enabling automation and machine learning, and integrating surface and downhole.

SLB has also been looking at new commercial models including its SPM offering that showcases its full range of technology and expertise while demonstrating the value of its technology as their compensation is directly linked to production generated. SLB recently created a special venture fund offering its customers a different way to pursue E&P project investment with the hope of fostering further collaboration and secure preferred supplier agreements. The company also announced a JV with WFT (OneStim) to offer a broad multistage completion portfolio in North America.

Changing how the business works

Traditionally the earnings drivers for the company have been spending by larger international oil companies (IOCs) and state-owned national oil companies (NOCs) and leveraging its scale and diversification to win large international contracts. Exploration spending was important as SLB's had a large competitive advantage in their service offerings in exploration and offshore deepwater. In a lower for longer environment, SLB is focusing on integration and new commercial models which leverage its scale and technological capabilities. This will require operators changing the way they procure products and services, interact with the company at a much earlier time in the planning stages, and in some cases allow SLB to take over the entire project.

Figure 564: Annual EPS



Source: Company reports, Deutsche Bank

OneStim JV with Weatherford

SLB is in the early stages of its JV with WFT called OneStim that was announced at the end of March 2017. The JV will offer one of the largest frac fleets in North America to deliver a broad multistage completion portfolio. SLB will own 70% of the JV while WFT will own 30%. The transaction is expected to close in the second half of this year. SLB and WFT contributed their entire North America pressure pumping assets, multistage completions, and pump down perforation businesses. SLB also paid a one-time $535mm payment to WFT. SLB will manage the JV and consolidate it for reporting purposes.

Uses of capital…we expect M&A will remain a core part of SLB's strategy

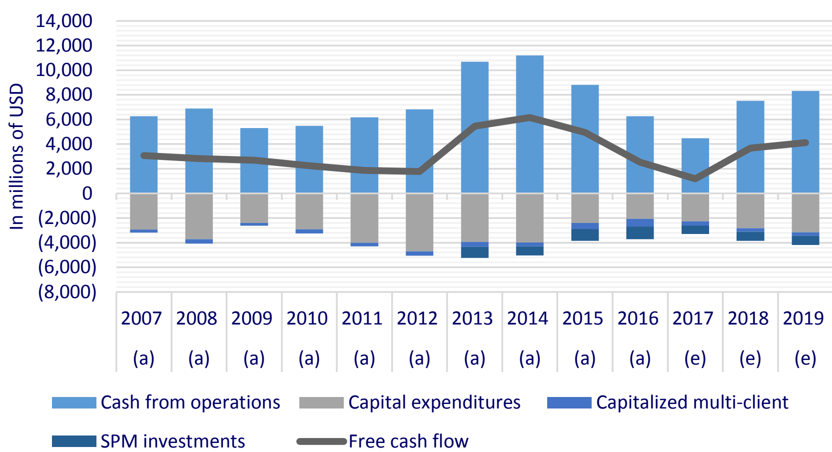
Primary uses of cash are working capital and capex to fund reactivation of equipment that was stacked during the downturn and to crew up. SLB actually waited longer than its peers to accelerate its reactivation of equipment as it was waiting for more profitable work to return. Therefore SLB will be burdened more than peers in the next quarter or two with reactivation costs.

The company estimates that 2017 capex will be close to $2.2bn. SLB also remains committed to investing in technology in the oil patch and generally has an annual R&D budget of roughly $1bn. Its R&D budget is larger than its peer group combined. The challenge facing SLB is getting clients to pay for new technology in a challenging operating environment. Therefore SLB has also used its own capital in funding SPM projects and its special venture fund as a way to showcase the results of its technology.

Also SLB spent $2.6bn in dividends and $0.78mm in stock repurchases in 2016. Given its acquisition of CAM, it took its buyback levels down from the $2.2bn in 2015 and $4.7bn in 2014. With its free cash flow levels likely to increase post the reactivation of equipment, look buybacks to return in force.

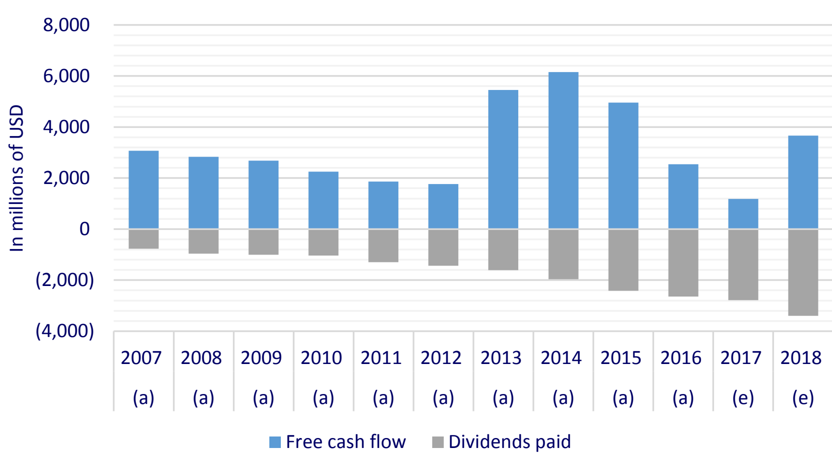
The one mitigating factor to an acceleration in buybacks is M&A. SLB has been active and vocal about the importance of its M&A strategy, which we fully expect will continue through 2018.

Figure 565: Free cash flow



Source: Company reports, Deutsche Bank

Figure 566: Consistent dividend growth paused during down cycle



Source: Company reports, Deutsche Bank

Figure 567: Income Statement

In millions of USD	(a) 2009	(a) 2010	(a) 2011	(a) 2012	(a) 2013	(a) 2014	(a) 2015	(a) 2016	(e) 2017	(e) 2018	(e) 2019
Segment revenue											
North America	3,707	6,003	12,273	13,448	13,898	16,151	9,811	6,665	9,078	10,646	12,867
Latin America	4,225	4,660	6,454	7,529	7,751	7,699	6,014	4,231	4,080	4,388	4,471
Europe/CIS/Africa	7,151	7,553	9,762	11,524	12,365	12,515	9,284	7,352	6,787	6,410	6,786
Middle East/Asia	5,234	6,078	8,071	9,180	10,909	11,875	9,898	9,285	10,137	10,730	12,547
Eliminations, other	2,386	3,153	2,980	1,160	441	340	467	277	494	528	602
Total revenues	22,702	27,446	39,540	42,841	45,364	48,580	35,474	27,810	30,575	32,703	37,273
Op costs	14,556	18,407	27,964	30,096	31,341	33,064	24,066	19,953	22,498	23,245	26,300
SG&A	535	650	417	405	406	476	493	404	431	449	449
R&D	802	919	1,061	1,153	1,174	1,218	1,095	1,011	799	784	784
D&A	2,476	2,775	3,280	3,501	3,764	4,094	4,078	4,094	3,900	3,612	3,421
EBIT	4,333	4,695	6,818	7,686	8,679	9,728	5,742	2,348	2,948	4,613	6,319
Interest (expense)	(221)	(206)	(298)	(331)	(369)	(347)	(316)	(517)	(501)	(476)	(452)
Interest income	60	54	40	31	23	31	30	84	95	65	51
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	0	0	0	0	0	0	0	0	0	0	0
PBT	4,171	4,543	6,560	7,386	8,333	9,412	5,456	1,915	2,541	4,202	5,918
Income tax (expense)	(801)	(936)	(1,575)	(1,757)	(1,903)	(2,063)	(1,102)	(306)	(478)	(880)	(1,279)
Non-controlling interest	(8)	0	(16)	(33)	(42)	(67)	(64)	(60)	(20)	(20)	(20)
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	3,363	3,608	4,969	5,596	6,388	7,282	4,290	1,549	2,044	3,302	4,618
Discontinued ops	(22)	(75)	220	33	(124)	(205)	(383)	0	0	0	0
Unusual after-tax	(207)	734	(195)	(139)	469	(1,639)	(1,835)	(3,236)	(68)	0	0
Net income (GAAP)	**3,134**	**4,267**	**4,994**	**5,490**	**6,733**	**5,438**	**2,072**	**(1,687)**	**1,976**	**3,302**	**4,618**
Operating EPS	**2.77**	**2.86**	**3.65**	**4.18**	**4.79**	**5.57**	**3.36**	**1.14**	**1.47**	**2.38**	**3.33**
GAAP EPS	2.59	3.38	3.67	4.10	5.05	4.16	1.62	(1.24)	1.42	2.38	3.33
DPS	0.84	0.84	1.00	1.10	1.25	1.51	1.90	2.00	2.00	2.45	3.19
Diluted shares	1,215	1,264	1,361	1,339	1,334	1,309	1,275	1,360	1,391	1,387	1,387
EBITDA	**6,809**	**7,470**	**10,098**	**11,187**	**12,443**	**13,822**	**9,820**	**6,442**	**6,848**	**8,225**	**9,740**
EBITDA margin	30.0%	27.2%	25.5%	26.1%	27.4%	28.5%	27.7%	23.2%	22.4%	25.2%	26.1%
EBIT margin	19.1%	17.1%	17.2%	17.9%	19.1%	20.0%	16.2%	8.4%	9.6%	14.1%	17.0%
Tax rate	19.2%	20.6%	24.0%	23.8%	22.8%	21.9%	20.2%	16.0%	18.8%	20.9%	21.6%

Source: Deutsche Bank

Figure 568: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	3,363	3,608	4,969	5,596	6,388	7,282	4,290	1,549	2,096	3,439	4,682
Depreciation	2,476	2,775	3,280	3,501	3,764	4,094	4,078	4,094	3,900	3,618	3,430
Deferred tax	373	(109)	(35)	(76)	(105)	0	0	0	0	0	0
Chg in receivables	155	(289)	(1,310)	(2,116)	(858)	(187)	2,176	1,098	(942)	356	(415)
Chg in inventories	64	(67)	(991)	(643)	188	(36)	625	800	(377)	273	(304)
Chg in payables	(293)	(103)	708	928	654	(36)	(2,656)	(1,680)	261	(18)	1,437
Other	(827)	(321)	(452)	(376)	659	78	292	400	(457)	(148)	(512)
Cash from operations	5,311	5,494	6,169	6,814	10,690	11,195	8,805	6,261	4,480	7,520	8,319
Capital expenditures	(2,395)	(2,914)	(4,016)	(4,695)	(3,943)	(3,976)	(2,410)	(2,055)	(2,260)	(2,823)	(3,160)
Capitalized multi-client	(230)	(326)	(289)	(351)	(394)	(321)	(486)	(630)	(338)	(296)	(296)
SPM investments	0	0	0	0	(902)	(740)	(953)	(1,031)	(696)	(736)	(736)
Free cash flow	2,686	2,254	1,864	1,768	5,451	6,158	4,956	2,545	1,186	3,665	4,127
Acquisitions	(514)	(1,101)	(186)	(845)	(1,210)	(1,008)	(443)	(2,398)	(364)	0	0
Asset sales	0	0	385	1,028	0	0	0	0	0	0	0
Dividends paid	(1,006)	(1,040)	(1,300)	(1,432)	(1,608)	(1,968)	(2,419)	(2,647)	(2,780)	(3,398)	(4,418)
ESPP | options	206	401	438	410	537	825	448	415	143	0	0
Equity issuance, net	(500)	(1,717)	(2,998)	(972)	(2,596)	(4,678)	(2,182)	(778)	(770)	0	0
Debt issuance, net	108	933	1,773	1,636	1,450	(37)	5,791	(2,377)	(2,447)	67	(700)
Other	(56)	644	(139)	(146)	72	(161)	(618)	1,463	180	0	0
Chg in cash	924	374	(163)	1,447	2,096	(869)	5,533	(3,777)	(4,852)	334	(991)
FCF per share	2.21	1.78	1.37	1.32	4.09	4.71	3.89	1.87	0.85	2.64	2.98
Capex / revenue	0.11	0.11	0.10	0.11	0.09	0.08	0.07	0.07	0.07	0.09	0.09
Capex / depreciation	0.97	1.05	1.22	1.34	1.05	0.97	0.59	0.50	0.58	0.78	0.92

Source: Deutsche Bank

Figure 569: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	4,616	4,990	4,827	6,274	8,370	7,501	13,034	9,257	4,405	4,739	3,748
Accounts receivable	6,088	8,278	9,500	11,351	11,497	11,171	8,780	9,387	9,461	9,105	9,520
Inventories	1,866	3,804	4,700	4,785	4,603	4,628	3,756	4,225	4,664	4,391	4,695
Other current assets	1,080	1,026	1,512	1,746	1,755	1,394	1,342	1,058	1,994	2,077	2,368
Total current assets	13,650	18,098	20,539	24,156	26,225	24,694	26,912	23,927	20,524	20,313	20,331
LT investments	738	484	256	245	363	442	418	238	13	13	13
Investment in affiliates	2,306	1,071	1,266	1,502	3,317	3,235	3,311	1,243	1,553	1,553	1,553
Net PP&E	9,660	12,071	12,993	14,780	15,096	15,396	13,415	12,821	11,809	11,015	10,745
Multi-client data	288	394	425	518	667	793	1,026	1,073	1,116	1,264	1,412
Goodwill	5,305	13,952	14,154	14,585	14,706	15,487	15,605	24,990	25,058	25,058	25,058
Intangible assets	786	5,162	4,882	4,802	4,709	4,654	4,569	9,855	9,636	9,636	9,636
Other assets	732	535	686	959	2,017	2,203	2,749	3,809	4,371	4,555	5,191
Total assets	33,465	51,767	55,201	61,547	67,100	66,904	68,005	77,956	74,081	73,406	73,938
Accounts payable	5,003	6,488	7,579	8,453	8,837	9,246	7,727	10,016	10,443	10,425	11,863
Income taxes payable	878	1,493	1,245	1,426	1,490	1,647	1,203	1,188	1,290	1,344	1,531
Dividends payable	253	289	337	368	415	518	634	702	694	902	1,172
Current debt	1,125	2,595	1,377	2,121	2,783	2,765	4,557	3,153	2,324	1,424	2,324
Other current liabilities	0	0	0	0	0	0	0	0	0	0	0
Total current liabilities	7,259	10,865	10,538	12,368	13,525	14,176	14,121	15,059	14,750	14,094	16,890
Long-term debt	4,355	5,517	8,556	9,509	10,393	10,565	14,442	16,463	15,000	15,967	14,367
Deferred taxes	0	1,636	1,731	1,493	1,708	1,296	1,075	1,880	2,000	2,000	2,000
Employee obligations	1,660	1,262	1,732	2,169	670	1,501	1,434	1,495	1,385	1,385	1,385
Other LT liabilities	962	1,043	1,252	1,150	1,169	1,317	1,028	1,530	1,555	1,621	1,847
Non-controlling int	109	218	129	107	166	199	272	451	442	462	482
Shareholders' equity	19,120	31,226	31,263	34,751	39,469	37,850	35,633	41,078	38,948	37,877	36,967
Total liabilities and equity	33,465	51,767	55,201	61,547	67,100	66,904	68,005	77,956	74,081	73,406	73,938
Total debt	5,480	8,112	9,933	11,630	13,176	13,330	18,999	19,616	17,324	17,391	16,691
Net debt	864	3,122	5,106	5,356	4,806	5,829	5,965	10,359	12,919	12,652	12,943
Debt/capital	22%	21%	24%	25%	25%	26%	35%	32%	31%	31%	31%
Debt/equity	29%	26%	32%	33%	33%	35%	53%	48%	44%	46%	45%
Debt turns	**0.8**	**1.1**	**1.0**	**1.0**	**1.1**	**1.0**	**1.9**	**3.0**	**2.5**	**2.1**	**1.7**

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Smart Sand

Reuters	Bloomberg
SND.OQ	SND US

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Price at 5 Oct 2017 (USD)	7.01
Price target	9.00
52-week range	21.00 - 4.94

Price/price relative

Performance (%)	1m	3m	12m
Absolute	17.2	-23.2	–
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	284.7
Shares outstanding (m)	40.6
Free float (%)	100
Volume (5 Oct 2017)	154,111
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Pushing Ahead with Expansion Efforts

Initiating coverage with a Buy rating and $9 price target

The higher cadence of more productive wells in the US has attracted a rapid deployment of upstream capital that is disproportionately benefiting two main disciplines, hydraulic fracturing and frac sand. We expect the bottleneck in the frac market to begin easing in early 2018, which should benefit sand demand and SND's expansion efforts. We are encouraged that the markets have rerated the stocks lower and expectations have been reduced broadly, thus we are initiating on SND with a Buy rating and a $9 price target. Our target is below historical trading ranges as the industry is re-investing rapidly to expand sand capacity, thus restoring the same scarcity value experienced in 2014 is unlikely in the near-term in our view.

SND expanding Oakdale facility to 5.5m tons from 3.3 million tons

The two dryers should be in-place by 2Q18, enabling SND to boost its capacity by two-thirds. Ultimately the expansion should improve cost efficiencies with production costs expected to decline to $12 per ton from the $16 per ton exit rate in 4Q16.

SND evaluating opportunities for a regional mine in the Permian

While the focus remains on the expansion of the Oakdale facility and further enhancements to its logistics, SND is looking to make a deal for a Permian sand mine by year-end 2017.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.01	0.02A	0.17
2Q EPS	-0.11	0.06A	0.21
3Q EPS	-0.00	0.11	0.23
4Q EPS	0.40	0.13	0.24
FY EPS (USD)	0.41	0.33	0.86
OLD FY EPS (USD)	0.26	–	–
% Change	58.9%	–	–
P/E (x)	32.7	21.5	8.1
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	59.2	126.2	195.0

Source: Deutsche Bank estimates, company data

Valuation

Our $9 price target is 5.5x our estimate of the company's 2018 EBITDA power of $69m, is below the three-year average multiple of its peers at 8.0x. The discount is applied to account for the scale of the company and its single source of operational cash flow, specifically the Oakdale facility. The opportunity for multiple expansion as the company diversifies is relevant to the story as the company looks at opportunities in the Permian.

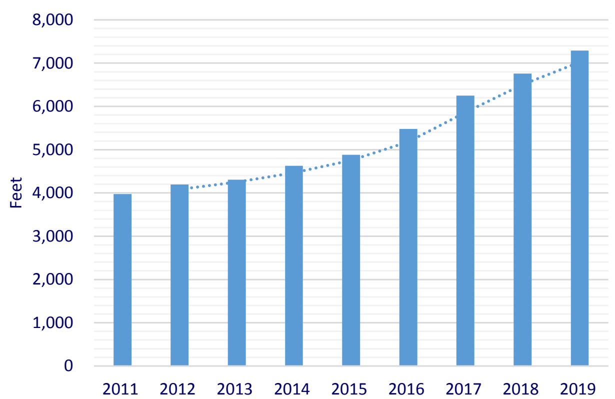
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a downdraft in pricing if supply additions overwhelm demand increases, and 4) operational disruptions at its single operating facility near Oakdale, which could disrupt earnings materially.

Key investment themes

Completion intensities rising, befitting sand demand

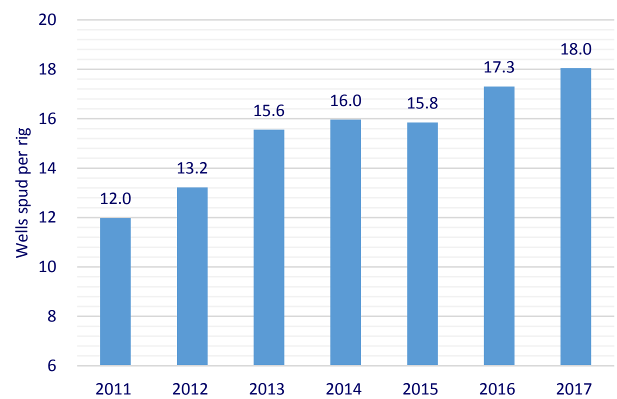
The sand industry is seeing a significant benefit from rising completion intensities. It is benefiting from a higher cadence of wells drilled per rig annually, more frac stages per well, longer laterals and increased proppant loadings per lateral foot. Well productivity has undergone a steady and significant move higher over the past decade which has caused operators to double down on completion intensity, further driving sand demand.

Figure 570: Average Permian horizontal lateral lengths



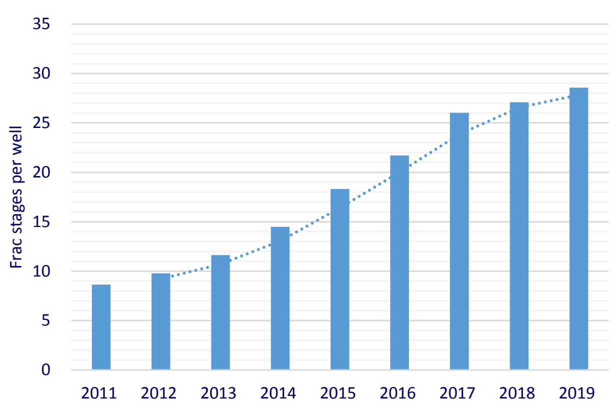
Source: IHS Markit

Figure 571: Wells spud per year per rig



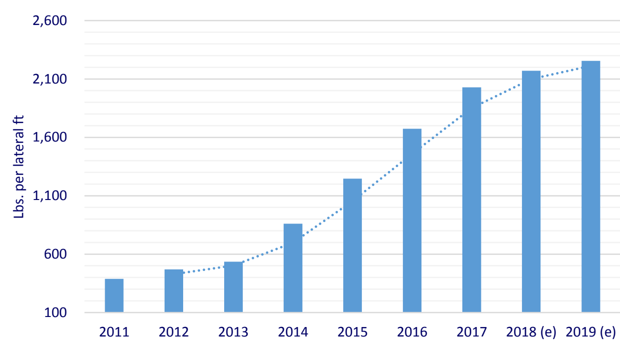
Source: IHS Markit

Figure 572: Permian frac stages per well



Source: IHS Markit

Figure 573: Permian sand volumes per lateral foot



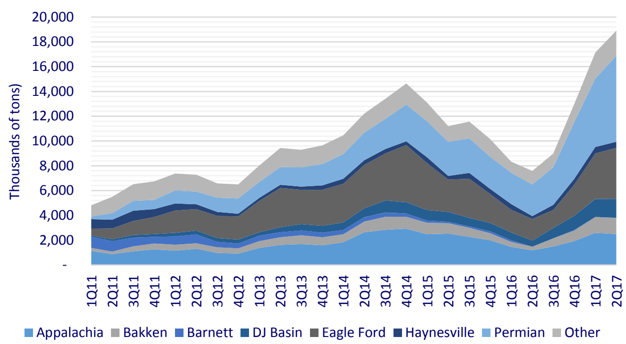
Source: IHS Markit

US sand demand totaled 18.9 million tons in 2Q17, up 11% sequentially and almost 150% year-over-year. The US rig count rebounded at a record pace starting in 2Q16 which provided a tailwind for demand. In addition, sand per well and sand per frac stage continued to set new record highs, driving consumption to record levels. Despite the low oil prices, 2017 consumption per should continue to rise, albeit at a much more moderate pace.

Permian is the largest demand destination, and is core market for SND

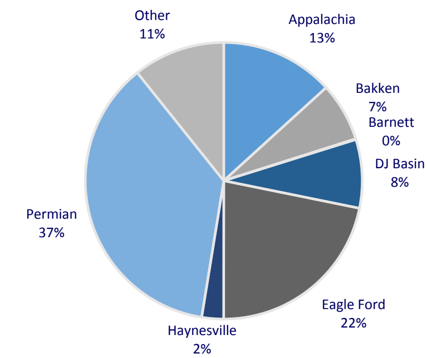
The Permian consumes more frac sand than any other region which is not surprising as the basin also boasts the highest level of drilling activity. During 2Q17, the Permian accounted for 37% of overall US sand consumption. The Eagle Ford is the second largest consumer of frac sand, accounting for 22% of overall US demand in 2Q17, followed by Appalachia at 13%. While sand consumption generally tracks the rig count in a particular region, each basin does exhibit different intensity metrics due to the geology of the rock and operators in the region. The Permian currently makes up about 38% of SND's sales, second only to the Marcellus which is a bit above 40% year-to-date.

Figure 574: Regional US sand demand



Source: IHS Markit, Deutsche Bank

Figure 575: US sand demand by region (2Q17)



Source: IHS Markit, Deutsche Bank

While overall sand intensity is expected to keep increasing, the rate of change is slowing on average. During the downturn, operators were pushing the envelope on sand loading to determine optimal intensity and maximum returns. Cheap sand prices and low rates for pumping services encouraged service providers to experiment with intensity levels. Completion has become the most expensive phase of the oil and gas cycle and given that sand is a very big piece of the completion cost, E&Ps have begun focusing on optimizing sand efficiency. Customers are spending to research well design, cluster spacing and sand loading techniques to get the most of their sand, particularly as some operators encounter some price break points in terms of sand volumes and the overall cost of the well.

SND evaluating regional mines in the Permian

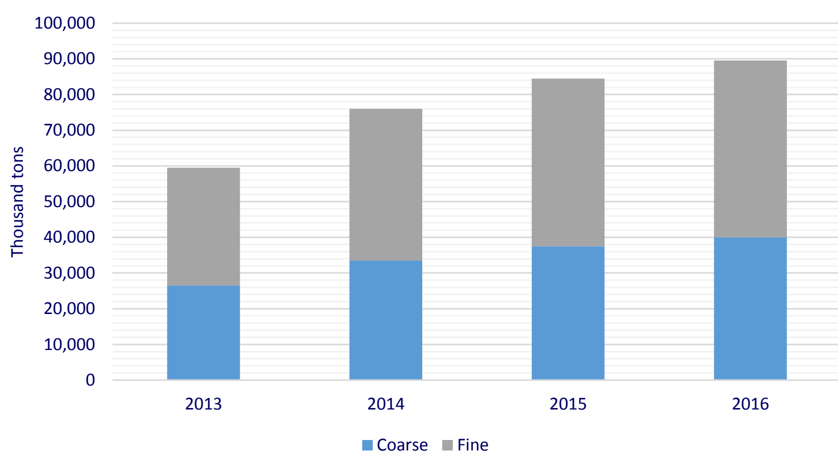
The most prominent shift in the frac sand market over the last five years has been the emergence of regional sand mines in Texas. In 2014, regional sand mines accounted for just 10% of total US demand however this spiked to 35% in 2016 and will continue to move higher as new capacity comes on line. Historically, the high majority of US sand demand was fulfilled by Midwest northern white frac mines which sport the highest quality reserves in the world. TX accounts for about 60% of US sand demand and thus the sand must be transported a long distance. In addition, the commodity has a very low value to weight ratio. These two factors caused transportation expenses to be about 70% of the total delivered price to the well. This presented an opportunity for regional sand mines in Texas as they could deliver the sand for significantly cheaper, allowing them to undercut the Midwest mines on pricing while still generating a healthy margin.

The northern white mines are higher quality than the regional brown deposits, exhibiting superior crush strength and roundness which is important as frac sand must be able to withstand high pressure and temperature. Prior to the downturn, it was considered taboo to use the regional brown sand which is lower quality however as oil prices crashed, operators searched for ways to bring down their cost profiles and breakevens and began experimenting with regional brown sand. To the industry's surprise, the regional brown sand performed well. SND has been very vocal about its intentions to invest in the Permian with timing being sometime near year-end 2017.

Robust demand has attracted significant supply additions, weighed on stock

While frac sand demand has the strongest tailwinds in the entire energy complex in our view, sand producers have aggressively added capacity to meet this rising demand, which is weighing on pricing leverage and the stocks. The sand market has made significant capacity additions over the last couple years due to surging demand. Despite the downturn and declining demand, industry capacity continued to move higher as previously announced supply additions came on with a lag.

Figure 576: Effective industry supply



Source: IHS Markit, Deutsche Bank

Year to date there has been 10-15 capacity additions which have been a combination of new mine/production facility start-ups along with expansions to existing plants. The majority of this capacity will come on-line by late 2017 or early 2018. The aggregate production capacity of the additions meant for the Permian Basin only is approximately 25MM tons per year (TPY). This has been a drag on the stocks, but has forced a re-rating and negative revisions that offer a better setup in the shares of SND now.

Valuation and risks

Our $9 price target is 5.5x our estimate of the company's 2018 EBITDA power of $69m, is below the three-year average multiple of its peers at 8.0x. The discount is applied to account for the scale of the company and its single source of operational cash flow, specifically the Oakdale facility. The opportunity for multiple expansion as the company diversifies is relevant to the story as the company looks at opportunities in the Permian.

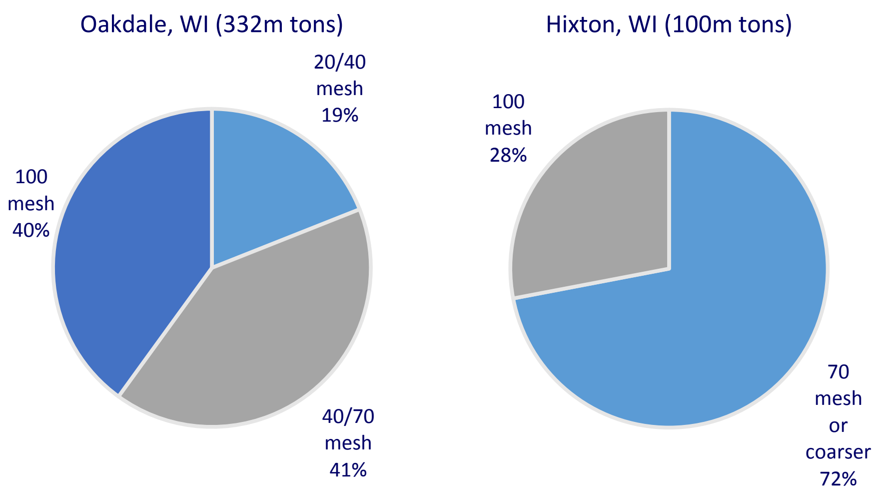
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) a downdraft in pricing if supply additions overwhelm demand increases, and 4) operational disruptions at its single operating facility near Oakdale, which could disrupt earnings materially.

Company description

Smart Sand (SND) is a pure play producer of Northern White raw frac sand with an annual capacity of 3.3 million tons, which is currently being expanded to 5.5 million tons by early 2018. The company owns two properties, the first of which is an integrated facility with mining, wet and dry sand processing and an onsite rail infrastructure with three rail loops located near Oakdale, WI. This property has a current annual nameplate capacity of 3.3 million tons and is being expanded to 5.5 million tons. It has proven reserves of 332 million tons, 80% of which is the fine mesh grades. The second property, the Hixton site, is in Jackson County, WI and has 100 million tons of proven reserves and is available for future development.

The company is also evaluating opportunities to acquire regional sand capacity and logistical assets in the Permian, and logistical assets in the Bakken and Marcellus. Management expects a transaction as early as year-end 2017.

Figure 577: Proven reserves



Source: Company reports

Onsite rail infrastructure is critical

At the Oakdale facility, SND has an onsite rail infrastructure that includes seven miles of track in a double-loop configuration that just had a third rail loop added in June 2017. The property also has a connection to a Class I rail line owned by Canadian Pacific with a three rail car loading facility. About 3.5 miles away in Byron, WI, SND built a second transloading facility on a second Class I rail line, this one owned by Union Pacific. The company is expanding this facility to be a unit train capable facility with completion in late 3Q or early 4Q17.

Principal Sources and Uses of Cash Flow

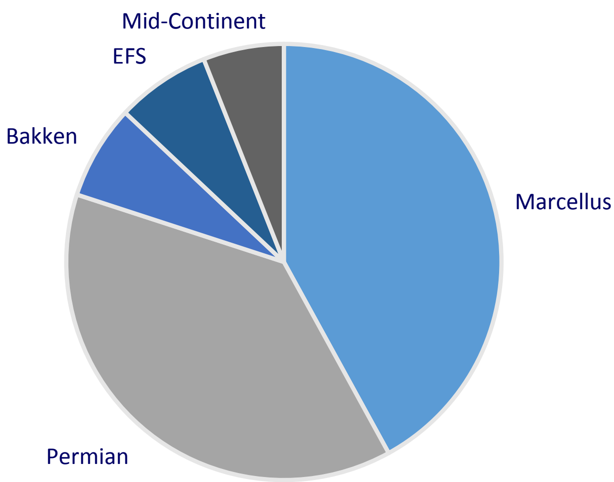
Oakdale facility is single source of cash flow, diversification coming soon

SND's primary focus remains growing its Oakdale facility and enhancing its logistics. This facility is the sole source of operating cash flow for the company, but there are plans to invest in a regional sand mine in West Texas with in-basin transloads, and last mile logistical opportunities. The company is also actively looking to acquire logistical assets in the Bakken and Marcellus. The timing of a regional sand mine transaction for the Permian is planned for by year-end 2017.

Permian are Marcellus are its principal markets

Year-to-date, SND's two primary destination markets have been the Permian and Marcellus, which combined are close to 80% of its delivered volumes. The company has been seeing increased interest from Basins other than the Permian including specifically the Bakken and Marcellus.

Figure 578: SND key sand destinations



Source: Company reports, Deutsche Bank

Expanding Oakdale to 5.5 million tons of annual capacity

In early 2017, SND decided to move forward with the expansion of the Oakdale facility to 5.5 million tons from its current nameplate capacity of 3.3 million tons. Ultimately SND can expand this facility to an annual capacity of 9 million tons. SND subsequently increased its capex guidance for 2017 to $85 million from $55 million. The company is building two dry plants and a wet plant in an integrated design, which will be enclosed so it can work year around. The wet plants should be up by September and the two dryers will online in late March or early April 2018. None of the expansion volumes have been contracted yet, but the company indicated it had good line-of-sight to move ahead with the investment. In February 2017, SND did a follow-on equity offering that provided net proceeds of about $24 million. Debt remains near zero.

Enhancing logistical infrastructure

In addition to the nameplate capacity expansion to 5.5 million tons, SND has also completed a third rail loop at Oakdale and is expanding its nearby Byron transloading facility to be a unit-train capable facility by late 3Q/early 4Q17. Logistics are crucial components of profitability and delivery flexibility and a key differentiator for SND. Having an onsite rail infrastructure eliminates trucking to a rail load-out facility and the higher associated costs. Having access to a Class I rail line provides direct access to the key unconventional plays and avoids interchange fees and local short hauls. By building out more unit train capabilities at its Byron location, SND also reduces the delivery time to its customers from 14+ days to less than 5 days by eliminating interim stops and also allowing for better rail car utilization. As these expansion efforts are completed, SND is expanding its fleet of railcars by 750 to a total of 2,300 railcars.

SND's business model favors long-term contracts

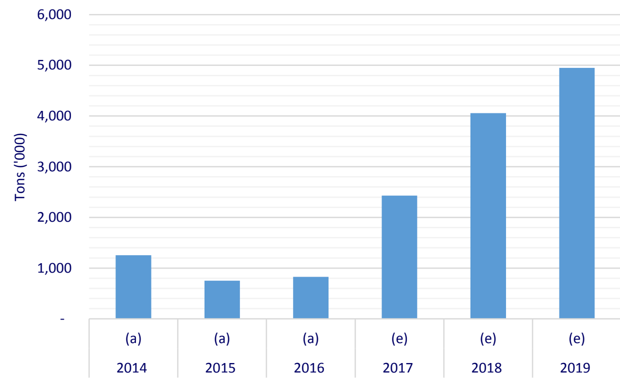
SND sells its sand volumes directly to producers and/or oilfield service companies under long-term take-or-pay contracts or in the spot market. The company recognizes revenues from direct sand sales, reservation charges and pass through charges for transportation. The company prefers to sell on a heavier mix of long-term take-or-pay contracts and currently has 74% of its annual capacity contracted with a weighted average term of just under three years. In 2Q17, 82% of SND's sales were from term commitments. The company looks for about 25% of its mix to be in the spot market.

Pricing for 40/70 mesh sand is in the mid-$40s per ton with 100 mesh in the $30s along with 30/50 mesh.

Production costs were $15.85 per ton in 1Q17 and down to $13.17 per ton in 2Q17. The company had initially guided to about $12 per ton as it planned for utilization to increase from 68% in 1Q17 to about 90% by 3Q17. However, there was some unplanned downtime due to dust control and some other operational issues, as well as some rail inefficiencies that have pushed the $12 per ton target to year-end 2017 or early 2018. The company now expects utilization in the 75-80% range for 3Q17 and rising into year-end.

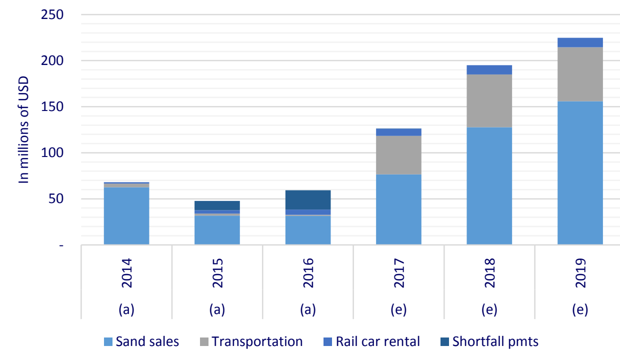
Transportation and logistical expenses are a significant portion of the costs incurred by the customer to bring sand to the well site. Suppliers with a closer proximity are a threat, which is why SND has invested in its expansive rail infrastructure, but is also evaluating its own entry into regional sand supply. In 2Q17, 82% of its volumes were sent by unit trains compared with 69% in 4Q16. The completion of the Byron expansion is meant to increase unit train takeaway and overall nameplate utilization, helping the company ramp to 90% utilization and get production costs down to $12 per ton.

Figure 579: SND sand volumes sold



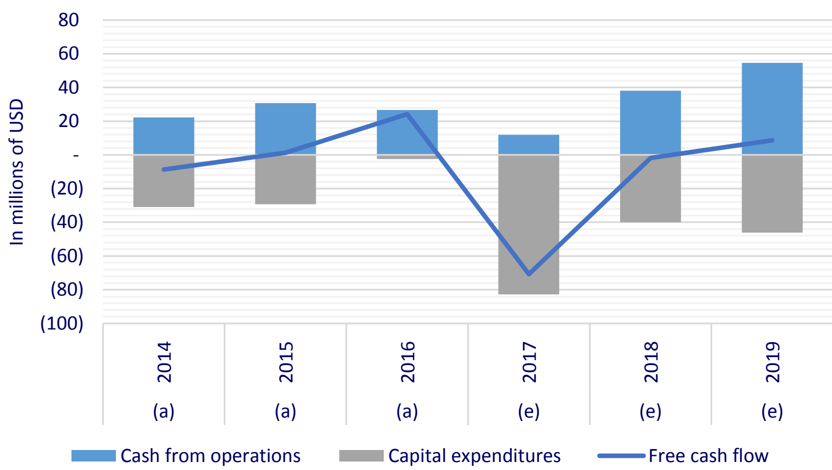
Source: Company reports, Deutsche Bank

Figure 580: SND revenues



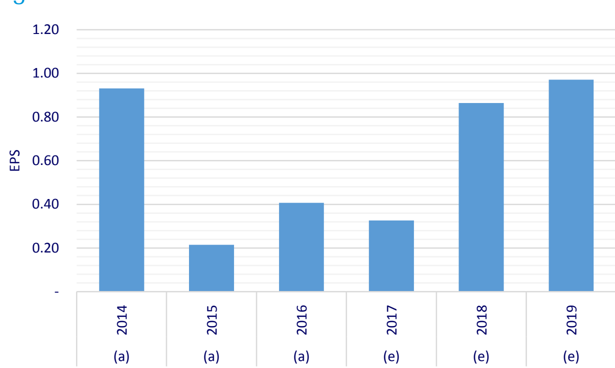
Source: Company reports, Deutsche Bank

Figure 581: Free cash flow



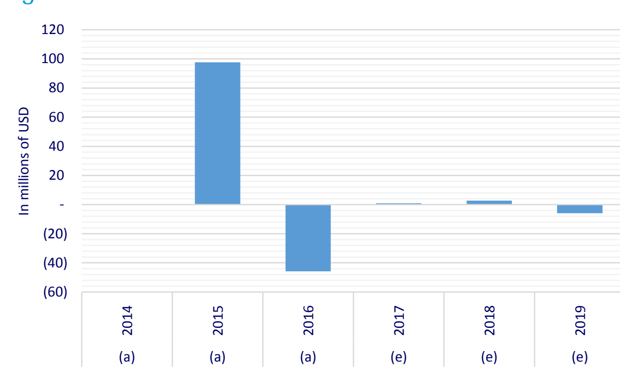
Source: Deutsche Bank

Figure 582: Annual EPS



Source: Company reports, Deutsche Bank

Figure 583: Net debt



Source: Company reports, Deutsche Bank

Figure 584: Income Statement

	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Revenues						
Sand sales	63	32	32	76	128	156
Transportation	4	2	1	42	57	59
Rail car rental	2	4	6	8	10	10
Shortfall pmts	-	10	21	0	-	-
Total revenues	68	48	59	126	195	225
COGS:						
DD&A	3	4	6	7	12	14
Freight	6	6	8	47	55	62
Production	21	10	13	32	49	59
Total COGS	30	21	27	87	115	135
Gross profit	38	27	33	39	80	89
Salaries	5	5	7	9	12	13
D&A	0	0	0	0	0	0
SG&A	5	4	5	10	12	13
EBIT	28	17	20	21	56	63
Interest (expense)	(2)	(3)	(3)	(0)	(0)	(0)
Interest income	-	-	-	-	-	-
Equity income	-	-	-	-	-	-
Other income	(6)	(5)	2	0	0	0
PBT	21	10	20	20	56	63
Income tax (expense)	(10)	(4)	(9)	(7)	(20)	(23)
Non-controlling interest	-	-	-	-	-	-
Preferred dividends	-	-	-	-	-	-
Net income (operating)	11	6	10	13	36	40
Discontinued ops	-	-	-	-	-	-
Unusual after-tax	(4)	(1)	-	-	-	-
Net income (GAAP)	**7**	**5**	**10**	**13**	**36**	**40**
Operating EPS	**0.93**	**0.21**	**0.41**	**0.33**	**0.86**	**0.97**
GAAP EPS	0.60	0.19	0.41	0.33	0.86	0.97
DPS	-	-	-	-	-	-
Diluted shares	12	26	25	41	41	41
EBITDA margin	47.1%	46.4%	45.3%	22.3%	34.8%	34.4%
EBIT margin	41.7%	36.2%	34.4%	16.3%	28.6%	27.9%
Tax rate	46.2%	42.1%	47.5%	34.9%	36.0%	36.0%

Source: Deutsche Bank

Figure 585: Cash Flow Statement

In millions of USD	(a) 2014	(a) 2015	(a) 2016	(e) 2017	(e) 2018	(e) 2019
Net income	7	25	10	13	36	40
Depreciation	4	2	6	8	12	15
Deferred tax	8	4	1	4	-	-
Chg in receivables	(4)	3	(3)	(13)	(10)	-
Chg in inventories	0	(2)	(1)	4	(4)	-
Chg in payables	1	(0)	1	0	2	-
Other	6	0	13	(5)	2	-
Cash from operations	22	31	27	12	38	55
Capital expenditures	(31)	(29)	(3)	(83)	(40)	(46)
Free cash flow	(9)	1	24	(71)	(2)	9
Acquisitions	-	-	-	-	-	-
Asset sales	-	-	0	0	-	-
Dividends paid	-	-	-	-	-	-
ESPP | options	-	-	-	-	-	-
Equity issuance, net	-	(0)	138	26	-	-
Debt issuance, net	48	2	(67)	20	-	-
Other	(39)	0	(51)	(2)	-	-
Chg in cash	-	4	44	(27)	(2)	9

Source: Deutsche Bank

Figure 586: Balance Sheet

	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	-	4	48	20	18	27
Accounts receivable	-	2	5	18	28	28
Unbilled receivables	-	4	0	0	0	0
Inventories	-	4	0	0	0	0
Other current assets	-	2	11	15	22	22
Total current assets	-	16	65	53	69	77
LT inventories	-	8	3	-	-	-
Net PP&E	-	109	104	182	210	241
Goodwill	-	-	-	-	-	-
Other assets	-	1	1	1	2	2
Total assets	-	133	173	237	281	321
Accounts payable	-	1	2	4	6	6
Current debt	-	36	1	0	0	0
Other current liabilities	-	11	11	10	16	16
Total current liabilities	-	49	14	15	22	22
Long-term debt	-	65	1	21	21	21
Other LT liabilities	-	16	16	21	22	22
Shareholders' equity	-	4	142	180	216	256
Total liabilities and equity	-	133	173	237	281	321
Total debt	-	102	2	21	21	21
Net debt	-	98	(46)	1	3	(6)
Debt/capital	0%	96%	1%	10%	9%	8%
Debt/equity	0%	2723%	1%	12%	10%	8%
Debt turns	**0.0**	**4.6**	**0.1**	**0.7**	**0.3**	**0.3**

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Superior Energy Services

Reuters	Bloomberg
SPN.N	SPN US

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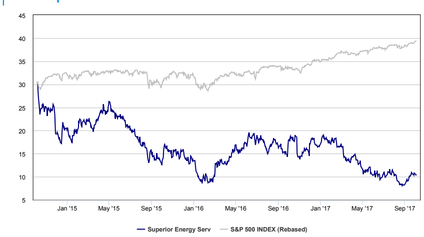
Price at 5 Oct 2017 (USD)	10.42
Price target	15.00
52-week range	19.03 - 8.12

Price/price relative



Performance (%)	1m	3m	12m
Absolute	25.2	-5.8	-40.8
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	1,583.5
Shares outstanding (m)	152.0
Free float (%)	100
Volume (5 Oct 2017)	683,510
Option volume (und. shrs., 1M avg.)	–

Source: Deutsche Bank

Choosing the Path

Maintaining our Buy rating and $15 price target

We are maintaining our BUY rating on Superior Energy Services and our price target of $15. SPN has benefitted from changing its strategic direction by investing capital into its US Land business when it recognized the opportunity to be an early responder by re-activating equipment early in the upcycle. Following solid execution in 2Q17, highlighted by strong US Land incrementals, SPN again wants the flexibility to put additional frac horsepower back to work but visibility into 2018 has become more uncertain. While headwinds in its Drilling Products and Services segment remain, with challenging offshore and international markets, the operating leverage in its US Land businesses should continue to come through and drive overall company margins higher.

Increasing US Land leverage

SPN positioned itself as an early responder and has deployed 250k hp since 2Q16 to get to 600k total capacity and will direct incremental capex towards US frac to grow their total horsepower to 750k by early next year. Rising service intensity, increasing utilization, and higher pricing have combined to drive strong US Land incrementals. US Land has become a larger part of the overall business, accounting for 68% of Q2 revenue vs. 44% a year earlier.

Geographic and earnings diversification

Some have questioned changes in SPN's strategic direction, but we believe its diversified portfolio allows it to adjust investment decisions. While the market may not fully value its diversification as International and Gulf of Mexico spending lags the US, geographic and earnings diversification remain a key part of the strategy. Management will direct incremental capex towards US frac and export key product lines abroad.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.49	-0.59A	–
2Q EPS	-0.53	-0.41A	–
3Q EPS	-0.73	-0.30	–
4Q EPS	-0.74	-0.25	–
FY EPS (USD)	-2.56	-1.53	-0.85
P/E (x)	–	–	–
DPS (USD)	0.08	0.00	0.00
Dividend Yield (%)	0.5	0.0	0.0
Revenue (USDm)	1,450.0	1,919.6	2,219.4

Source: Deutsche Bank estimates, company data

Valuation

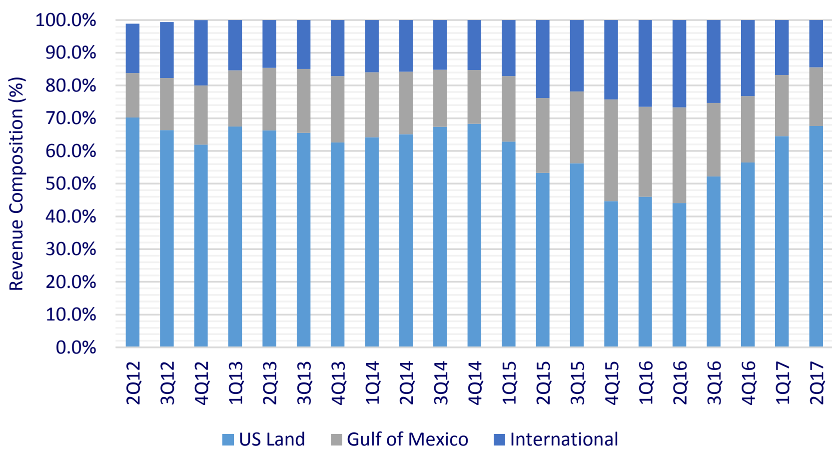
We are continuing coverage of Superior Energy Services with a $15 price target. This is based on a 9.4x EV/ EBITDA multiple of our 2018 EBITDA estimate. Our target multiple is based on a one-year forward (relative to the S&P 500) through-cycle EBITDA multiple applied to the historical average through-cycle multiple for SPN. The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) a step up in cost inflation in the US, 3) increased regulation around hydraulic fracturing, 4) geographic expansion as SPN continues to export key product lines abroad, 5) offshore spending levels continue to remain subdued.

Key investment themes

Increasing US Land leverage

US Land continues to become a larger part of their overall business, as US Land revenue accounted for 68% of total Q2 revenue compared to 44% a year earlier. After closing its pressure pumping operations in the Marcellus, SPN is leveraging its scale by focusing its pressure pumping assets in the Permian and the Eagle Ford plays. SPN has gone from 350,000 hp working at the end of 2Q16 to 600,000 hp working at the end of 2Q17. Management will direct incremental capex towards US frac to grow their total horsepower to 750k by early next year. While this horsepower will likely leave them just outside the top 10 in total US capacity, SPN focuses on a select subset of efficient customers in two plays which provides them enough scale to service their customers.

Figure 587: Increasing US Land exposure

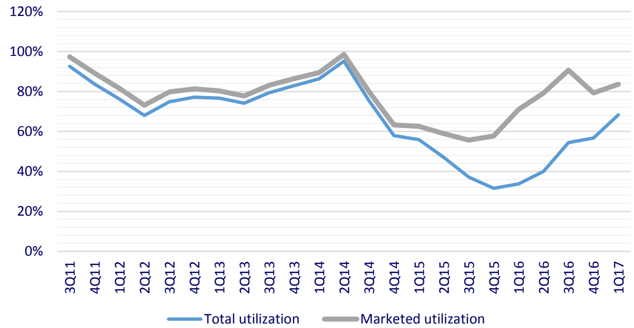


Source: Company reports, Deutsche Bank

US pressure pumping market is undersupplied

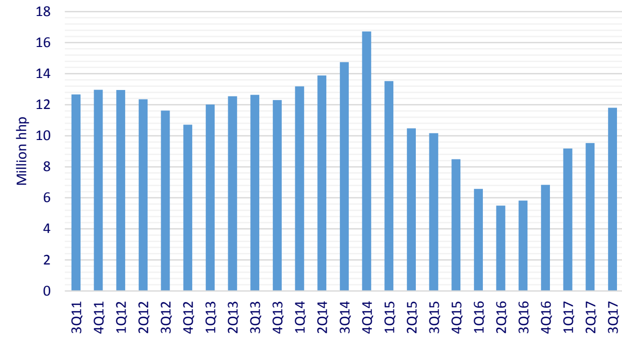
The positive supply/ demand trends are continuing in the frac market, driven by a rising well count, increased pad drilling, more wells per pad, and an increasing inventory of drilled but uncompleted wells. Frac fleets are also incorporating more hhp, averaging about 50k now. With these trends in mind, SPN decided to build out its total capacity to 750k hhp by early next year. While pricing has improved, it has been more moderate than what some producers previously expected. SPN also benefits from higher completion oriented spending with some of its complimentary product lines such as coiled tubing.

Figure 588: Total vs. marketed frac hhp utilization



Source: IHS Markit, Deutsche Bank

Figure 589: US frac hhp demand



Source: IHS Markit, Deutsche Bank

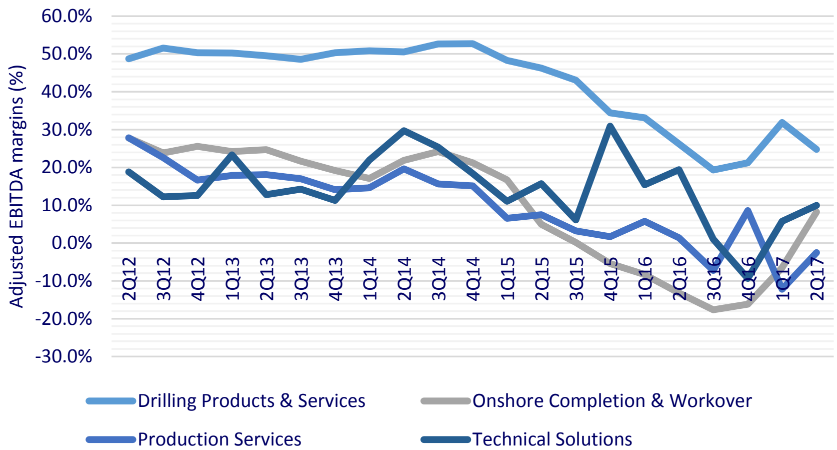
Smid cap diversified oilfield services provider

SPN is a smid-cap company with enough product depth and breadth to compete in the global diversified oilfield services market. Even with operations in 20 countries and 22 product line offerings, people still question the diversified services model with a company this size. The market tends to be more familiar with smid cap companies that specialize in a smaller subset of products or in one or two regions. We argue that the model does provide optionality when offshore and international markets start to improve. SPN also has more leverage to completion and production services markets internationally than the large cap diversifieds, therefore they are not always in direct competition.

Challenging offshore and international markets weigh on margins

As activity levels have remained challenging in offshore and international markets, there has been a drag in SPN's results due to its exposure to these markets and the impact on its high margin DPS business. In the Gulf of Mexico, management has done a good job lowering its cost structure and focusing on completion related work as drilling activity remains subdued. While the company strives to protect its leading drilling products market share, they have looked for opportunities to improve its DPS utilization by transferring under-utilized 5.5 inch drillpipe onshore. Also SPN's subsea plug and abandonment system should return to work in the fourth quarter. Internationally, SPN has selectively entered countries usually being pulled by a customer through an individual product line before expanding with additional lines. Its core markets exist in Latin America, Middle East, and Asia Pacific. While activity has been disappointing overall, they see a couple of emerging opportunities moving into next year. Improving DPS utilization, which carry high EBITDA margins, remains an important focus going forward.

Figure 590: Falling offshore and international activity levels have hurt DPS margins

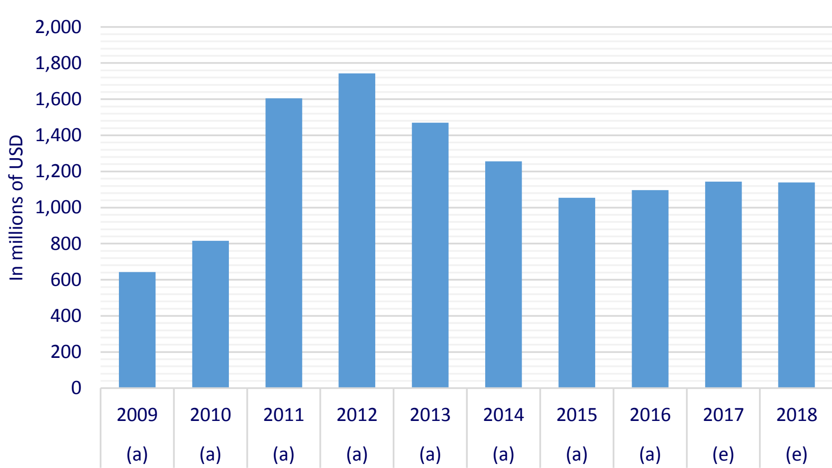


Source: Company reports, Deutsche Bank

Debt reduction remains a focus

Management has clearly stated the goal of paying down debt to enter the next cycle with much lower leverage. Part of the plan is to use proceeds from divestitures of product lines that no longer fit within its core portfolio. While not giving a specific target, management will have to find the right balance between the cyclicality in US Land compared with the general stability (at least in terms of staying EBITDA positive during the downturn) of its other geomarkets.

Figure 591: Net debt levels higher than management would like



Source: Company reports, Deutsche Bank

Valuation and risks

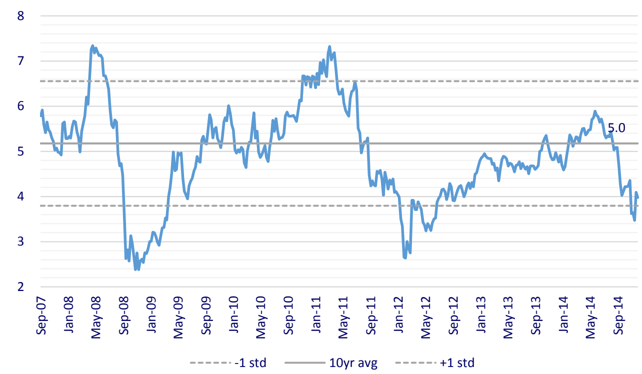
We are continuing coverage of Superior Energy Services with a $15 price target. This is based on a 9.4x EV/ EBITDA multiple of our 2018 EBITDA estimate. Our target multiple is based on a one-year forward relative (to the S&P 500) through-cycle EBITDA multiple applied to the historical average through-cycle multiple for SPN. The company is trading at 7.6x our 2018 EBITDA estimate of $359mm.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) a step up in cost inflation in the US, 3) increased regulation around hydraulic fracturing, 4) geographic expansion as SPN continues to look to export key product lines abroad, 5) offshore spending levels continue to remain subdued.

Figure 592: EV/ EBITDA band has blown out

Source: Factset

Figure 593: The 5yr EV/EBITDA leading up to 2014

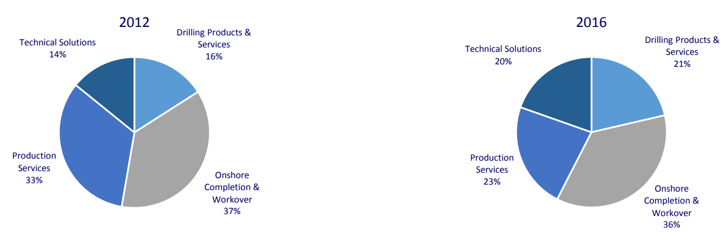


Source: Factset

Company description

Superior Energy Services is a mid-cap, global diversified provider of oilfield services and equipment. The company significantly changed its business profile in 2012 by exiting the liftboat business and through its acquisition of Complete Production Services. In its history, SPN has transitioned from a shallow water Gulf of Mexico liftboat and decommissioning player to an international diversified services provider that operates in three geomarkets – US Land, Gulf of Mexico (GoM), and International.

Figure 594: Revenue mix



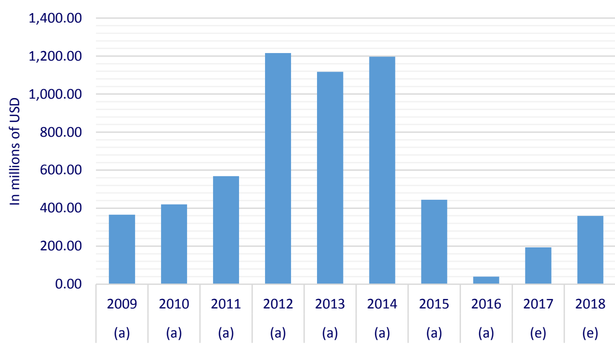
Source: Company reports

Principal Sources and Uses of Cash Flow

The primary contributors of free cash flow during the downturn has been SPN's DPS segment which generated $21.8mm in EBITDA in 1Q17 while its Onshore Completion & Workover and its Production Services segments each generated losses. In 2016, while DPS only accounted for 21% of total revenue, it generated $80mm in EBITDA. This segment and the more stable International business has allowed SPN to mainly stay free cash flow positive during the downturn. SPN also suspended its dividend in 2Q16 to preserve cash and have not repurchased shares since 2014. They have used cash to reactivate equipment and hire crews in the early stages of the upcycle to be positioned as first responder.

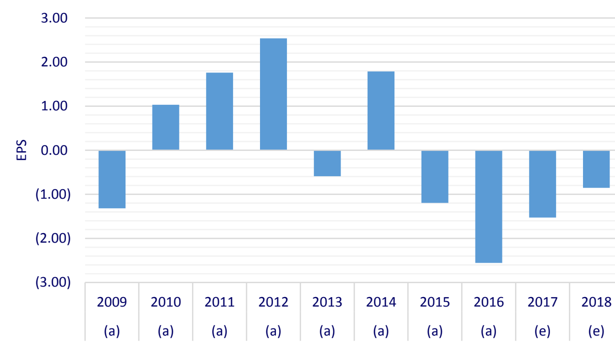
Primary uses of free cash flow are working capital and capex to fund reactivation of pressure pumping assets that were stacked during the downturn and crew up the equipment. SPN has so far spent/ expensed around $30mm to reactivate 200,000hp since the end of 2Q16 to the end of 1Q17. They will expense another $7-8mm to reactivate another 50,000hp. The company does not capitalize repair and maintenance costs for replacing engines, transmissions, or pumps. SPN has kept its capex spend low since the downturn started and so far in the early stages of the recovery.

Figure 595: Consolidated EBITDA



Source: Company reports, Deutsche Bank

Figure 596: Earnings remain negative



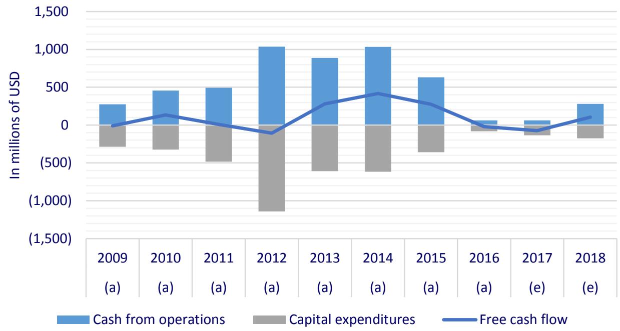
Source: Company reports, Deutsche Bank

Balance Sheet and FCF

SPN's management has clearly stated its goal of paying down debt to enter the next cycle with much lower leverage. CEO Dunlap has said that if they decide to divest product lines that no longer fit within its core portfolio, proceeds from those divestitures will be used to reduce debt levels. While not giving a specific target, Dunlap has said that it will be about finding the right balance between the cyclicality in US Land with its other geomarkets that stayed mostly EBITDA positive during the downturn. Also impacting its net debt to cap ratio was that SPN recorded a reduction in the value of its assets of $500.4mm in 2016 and $1.74bn in 2015, mainly due to an impairment of goodwill in its Onshore Completion & Workover and Production Services segments.

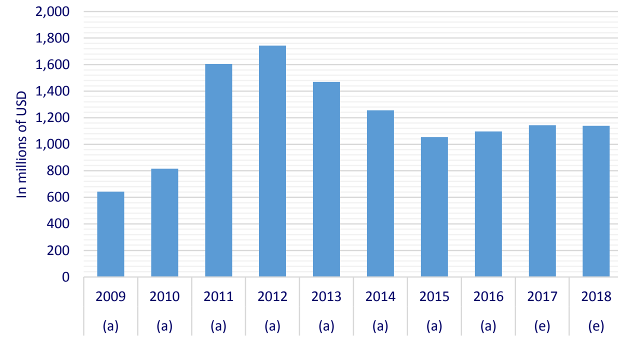
SPN has just under $1.3bn in debt outstanding, consisting of two senior notes. One senior note has outstanding $500mm, matures in May 2019 with a 6 3/8% interest rate. The other has $800mm outstanding, matures in December 2021 with a 7 1/8% interest rate. The company also has a $300mm revolver with a $100mm accordion feature. They amended the revolver in February which reduced the size from $400mm but allowed SPN to suspend the interest coverage ratio covenant until 3Q17.

Figure 597: Free cash flow turning positive



Source: Company reports, Deutsche Bank

Figure 598: Net debt



Source: Company reports, Deutsche Bank

Figure 599: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Segment revenues												
Drilling Products & Services							839	924	590	310	280	290
Onshore Completion & Workover							1,597	1,728	934	524	1,020	1,228
Production Services							1,446	1,356	760	332	356	408
Technical Solutions							682	549	490	284	265	294
Total revenues	1,572	1,881	1,449	1,682	2,070	4,568	4,563	4,557	2,775	1,450	1,920	2,219
Segment gross profit												
Drilling Products & Services							562	634	386	168	149	171
Onshore Completion & Workover							513	526	181	37	196	321
Production Services							434	411	172	77	61	90
Technical Solutions							237	251	216	110	107	126
Total gross profit	874	983	625	763	952	1,879	1,747	1,822	955	391	513	707
SG&A	228	283	259	343	384	663	630	624	511	351	319	348
EBITDA	646	700	366	420	569	1,216	1,117	1,197	445	40	194	359
D&A	188	176	207	221	257	509	621	651	612	510	446	473
EBIT	458	525	159	199	311	707	496	547	(167)	(470)	(252)	(114)
Interest (expense), net	(33)	(47)	(51)	(57)	(74)	(118)	(105)	(97)	(97)	(93)	(97)	(85)
Other Income (expense)	3	23	2	(17)	(24)	22	5	(8)	(9)	6	0	0
PBT	428	501	110	125	213	611	396	442	(274)	(556)	(349)	(198)
Income tax (expense)	151	191	37	43	79	225	145	161	(94)	(169)	(117)	(69)
Net Income (operating)	277	311	73	82	134	386	250	281	(180)	(387)	(232)	(129)
Unusual after-tax	5	41	(176)	0	9	(3)	(345)	(23)	(1,666)	(497)	0	0
Net Income GAAP	**281**	**351**	**(102)**	**82**	**143**	**383**	**(94)**	**258**	**(1,845)**	**(885)**	**(232)**	**(129)**
Operating EPS	**3.35**	**3.82**	**0.94**	**1.03**	**1.65**	**2.56**	**1.56**	**1.79**	**(1.19)**	**(2.56)**	**(1.53)**	**(0.85)**
GAAP EPS	3.41	4.32	(1.32)	1.03	1.76	2.54	(0.59)	1.64	(12.26)	(5.84)	(1.53)	(0.85)
DPS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.32	0.08	0.00	0.00
Diluted shares	82	81	78	79	81	151	160	157	150	152	152	151
Consolidated EBITDA	646	700	366	420	569	1,216	1,117	1,197	445	40	194	359
EBITDA margin	41.1%	37.2%	25.3%	25.0%	27.5%	26.6%	24.5%	26.3%	16.0%	2.8%	10.1%	16.2%
EBIT margin	29.1%	27.9%	11.0%	11.8%	15.0%	15.5%	10.9%	12.0%	-6.0%	-32.4%	-13.2%	-5.1%
Tax rate	35.4%	38.1%	33.6%	34.6%	37.1%	36.8%	36.7%	36.5%	34.5%	30.4%	33.5%	35.0%
Segment gross margins												
Drilling Products & Services							67.1%	68.6%	65.4%	54.1%	53.3%	58.9%
Onshore Completion & Workover							32.1%	30.5%	19.4%	7.0%	19.2%	26.2%
Production Services							30.0%	30.3%	22.7%	23.1%	17.2%	22.0%
Technical Solutions							34.8%	45.7%	44.0%	38.7%	40.4%	42.7%

Source: Company reports, Deutsche Bank

Figure 600: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Net Income	281	351	(102)	143	16	366	(111)	258	(11)	(887)	(236)	(129)
D&A	188	176	207	221	59	509	621	652	162	510	446	473
Deferred tax	62	104	(75)	8	(2)	11	14	(50)	(5)	(143)	(41)	(10)
Change in working capital	(12)	(222)	(64)	61	(5)	104	(99)	141	337	(24)	(117)	(54)
Other	12	(6)	311	24	426	45	463	31	150	604	9	0
Cash from operations	530	402	276	456	493	1,035	888	1,033	633	61	63	280
Capital expenditures	(411)	(454)	(286)	(323)	(485)	(1,142)	(609)	(616)	(358)	(81)	(136)	(175)
Free cash flow	120	(52)	(10)	133	8	(107)	279	417	274	(19)	(73)	105
Acquisitions	(119)	(8)	(1)	(276)	(2)	(1,091)	(24)	(24)	(46)	0	0	0
Asset sales	27	152	0	0	0	1,076	27	166	16	6	35	0
Dividends	0	0	0	0	0	0	0	(50)	(48)	(12)	0	0
Equity issuance, net	(25)	(98)	3	3	10	15	(4)	(289)	9	0	0	(100)
Debt issuance, net	(1)	(1)	176	(3)	799	147	(168)	(19)	(27)	(338)	(25)	0
Other	11	0	(6)	(13)	(786)	(29)	(10)	5	(7)	(14)	(7)	0
Chg in cash	13	(7)	162	(156)	30	11	100	205	171	(376)	(70)	5
FCF per share	1.45	(0.63)	(0.13)	1.67	0.10	(0.71)	1.74	2.65	1.82	(0.13)	(0.48)	0.69
Capex / revenue	0.26	0.24	0.20	0.19	0.23	0.25	0.13	0.14	0.13	0.06	0.07	0.08
Capex / depreciation	(2.19)	(2.59)	(1.38)	(1.46)	(8.16)	(2.24)	(0.98)	(0.94)	(2.21)	(0.16)	(0.31)	(0.37)

Source: Company reports, Deutsche Bank

Figure 601: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)
In millions of USD	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Cash and equivalents	52	45	207	51	80	91	196	393	564	188	118	122
Accounts receivable	343	360	337	452	541	1,027	937	927	429	297	452	510
Prepaid expenses	20	18	20	26	34	93	70	75	42	37	43	43
Inventory & other current assets	56	224	300	235	228	249	273	334	260	260	223	257
Total current assets	471	647	864	764	883	1,460	1,476	1,729	1,295	782	835	933
Net PP&E	878	1,115	1,059	1,313	1,507	3,255	3,002	2,734	2,123	1,605	1,296	998
Goodwill	485	478	482	588	581	2,532	2,458	2,468	1,140	804	804	804
Other assets	423	250	112	242	1,076	555	475	446	356	279	248	248
Total assets	2,257	2,490	2,517	2,908	4,048	7,803	7,411	7,377	4,914	3,470	3,184	2,983
Accounts payable	70	87	63	110	179	252	216	225	114	95	108	129
Current debt	1	1	1	185	1	20	20	21	30	0	0	0
Other current liabilities	222	210	164	211	214	500	403	466	304	250	245	264
Total current liabilities	292	298	228	506	394	772	639	712	449	345	354	392
Long-term debt	711	654	849	682	1,685	1,815	1,647	1,628	1,588	1,285	1,261	1,261
Other LT liabilities	273	283	262	439	516	985	994	958	667	537	500	264
Shareholders' equity	981	1,254	1,178	1,281	1,454	4,231	4,131	4,080	2,211	1,304	1,069	1,137
Total liabilities and equity	2,257	2,490	2,517	2,908	4,048	7,803	7,411	7,377	4,914	3,470	3,184	3,055
Total debt	712	655	849	866	1,686	1,835	1,667	1,649	1,618	1,285	1,261	1,261
Net debt	660	610	643	816	1,606	1,743	1,470	1,256	1,054	1,097	1,144	1,139
Debt/capital	42%	34%	42%	40%	54%	30%	29%	29%	42%	50%	54%	53%
Debt/equity	73%	52%	72%	68%	116%	43%	40%	40%	73%	99%	118%	111%
Debt turns	**1.1**	**0.9**	**2.3**	**2.1**	**3.0**	**1.5**	**1.5**	**1.4**	**3.6**	**32.0**	**6.5**	**3.5**

Source: Company reports, Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Transocean

Reuters	Bloomberg
RIG.N	RIG US

David Havens
Research Analyst
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Price at 5 Oct 2017 (USD)	10.54
Price target	13.00
52-week range	15.84 - 7.28

Industry Leading Backlog with Good Cash Preservation

Initiating coverage with a Buy rating and an $13 price target

This is the most challenging market environment ever experienced in the deepwater with a supply demand imbalance that is prompting fiercely competitive pricing tactics in an otherwise laboriously slow recovery in our view. But we believe the alpha short is gone for the offshore drillers, and with RIG specifically, the company's fleet is well positioned competitively and it has preserved cash well to allow it to opportunistically take advantage of the protracted downturn. With its $10 billion in backlog and $4.1 billion of backlog forthcoming from the Songa Offshore acquisition, Transocean presents the best setup in an otherwise difficult offshore drilling landscape.

$10 billion in backlog with the Songa deal bringing another $4.1 billion

The Songa deal will bring another $0.4 billion in annual EBITDA and $4.1 billion in backlog. The deal is expected to close in 4Q17. We expect Transocean will continue to seek more transactions to build on its scale.

Cash obligations are minimal through 2019, staying free cash flow positive

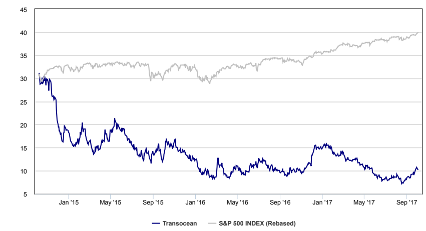
Transocean has been free cash flow positive each year except one since 2007, despite the most severe deepwater downturn in history. Debt obligations are less than $0.5 billion in 2018 and 2019 combined with capex less than $200 million each year until 2020 when it jumps to $1 billion for the completion of its two remaining newbuilds.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	0.24	0.01A	-0.18
2Q EPS	0.17	0.00A	-0.21
3Q EPS	0.25	0.02	-0.25
4Q EPS	0.24	0.00	-0.31
FY EPS (USD)	0.91	0.03	-0.94
OLD FY EPS (USD)	0.83	–	–
% Change	9.0%	–	–
P/E (x)	11.8	313.3	–
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	3,783.0	2,992.0	2,608.5

Source: Deutsche Bank estimates, company data

Price/price relative



Performance (%)	1m	3m	12m
Absolute	20.2	18.7	8.1
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	4,118.5
Shares outstanding (m)	390.8
Free float (%)	100
Volume (5 Oct 2017)	2,620,336
Option volume (und. shrs., 1M avg.)	1,492,477

Source: Deutsche Bank

Valuation & Risks

We are initiating coverage of Transocean with a $13 price target. This is 5.0x our estimate of the company's normalized EBITDA of $1.8 billion, which is one-turn below the 6.0x five-year average multiple of 6.0x. The company is currently trading at 8.3x our fiscal 2018 EBITDA estimate of $1.0 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

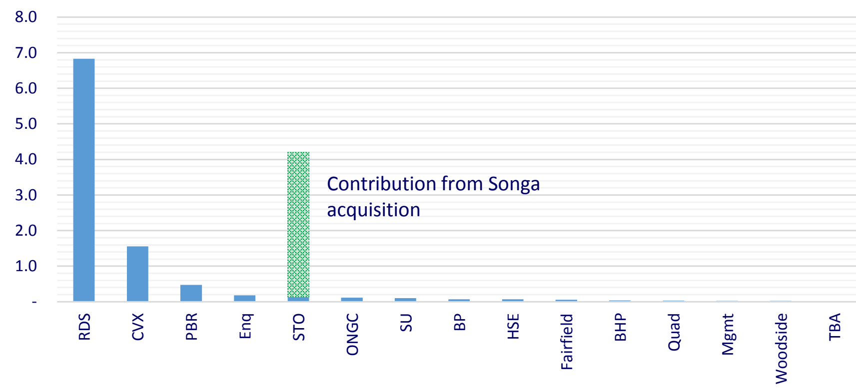
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) more M&A with Transocean as the suitor, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Key investment themes

Songa Offshore acquisition will add 40% to backlog

Before accounting for the Songa Offshore transaction, Transocean has $9.7 billion of backlog concentrated largely with two customers, Shell (70%) and Chevron (16%). Pro-forma the deal, Statoil becomes the second largest customer (31%) after Shell (50%) followed by Chevron (11%). The average dayrate across Songa Offshore's fleet of four working harsh environment semis is about $475 kpd versus less than $300 kpd for Transocean's harsh environment segment.

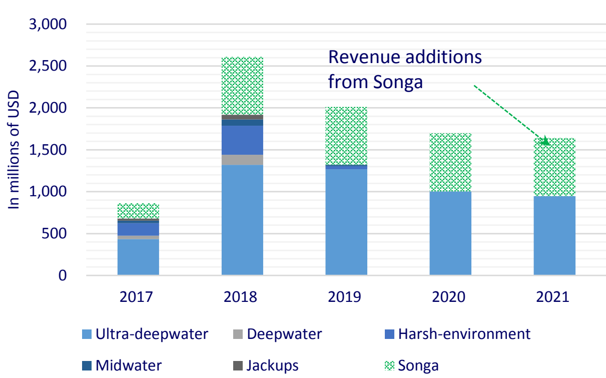
Figure 602: Backlog by customer



Source: Company reports, Deutsche Bank

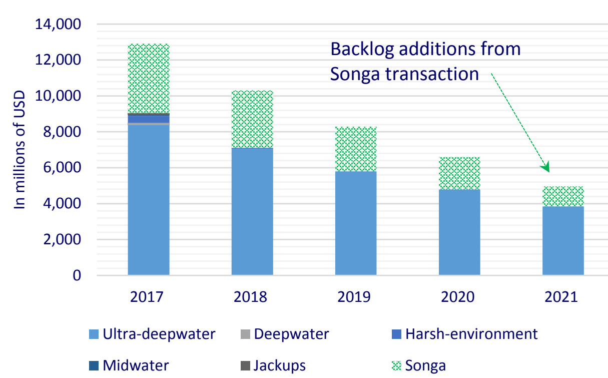
The deal adds about $0.7 billion of revenues each year through 2022, which is a 50% increase to Transocean's 2019 revenues from backlog and a 70% increase to 2020 revenues from backlog.

Figure 603: Revenues in backlog



Source: Company reports, Deutsche Bank

Figure 604: Year-end backlog



Source: Company reports, Deutsche Bank

Transocean acquiring Songa Offshore for a total consideration of $3.4 billion

Transocean announced it has an agreement to acquire Songa Offshore for a total consideration of $3.4 billion, which includes $1.7 billion of net debt. RIG is paying a 37% premium to Songa Offshore's (SONG-OSL) pre-announcement closing price and is getting four high-specification, harsh-environment semis with approximately $4.1 billion of backlog. Songa also has three other semis that are stacked, which we would classify as none core to Transocean in the long-run.

All seven of the Songa's semis are in Norway, with the four contracted units all with Statoil at an average daily rate of $475 kpd. These four units are 6th generation semis with long-term contracts that extend as far as 2024.

To fund the purchase price, RIG will issue $540 million of equity, $660 million of convertible bonds, and use $480 million of cash. RIG expects $40 million of synergies.

Transocean is paying 8.3x Songa Offshore's 2018 consensus EBITDA of $412 million, in-line with where Transocean is trading on its 2018 consensus of $974 million.

RIG preserved cash well during these extraordinarily challenging markets

In the ten years leading into 2017, Transocean generated cumulative free cash flow of over $13 billion and we expect from 2017 through 2019 it will generate another $0.9 billion in free cash. The company has about $1 billion of capital calls in 2020 related to its two uncommitted newbuild drillships, which will draw cash balances down to about $1 billion by year-end 2020 without any withdraws from its credit facility. This is a far cry from where the consensus pegged its fiscal stability two years ago.

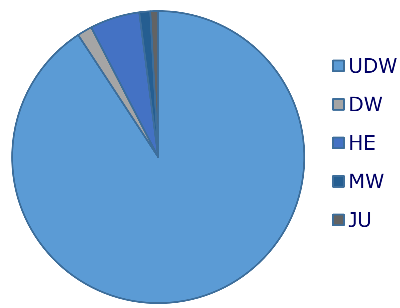
Figure 605: Transocean backlog details (excluding Songa Offshore)

Revenue in backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	434	1,320	1,267	1,003	948
Deepwater	39	121	0	0	0
Harsh-environment	150	348	37	0	0
Midwater	29	73	15	0	0
Jackups	28	57	0	0	0
Total backlog	**680**	**1,918**	**1,319**	**1,003**	**948**
			2,011	52%	

Total backlog	Abbrev	($bn)
Ultra-deepwater	UDW	8.8
Deepwater	DW	0.2
Harsh-environment	HE	0.5
Midwater	MW	0.1
Jackups	JU	0.1
Total backlog		**9.7**

Days committed	2017	2018	2019	2020	2021
Ultra-deepwater	38%	27%	24%	18%	17%
Deepwater	100%	81%	0%	0%	0%
Harsh-environment	81%	46%	5%	0%	0%
Midwater	50%	37%	10%	0%	0%
Jackups	100%	54%	0%	0%	0%
Total backlog	**53%**	**35%**	**17%**	**12%**	**11%**

Backlog by rig type



Year-end backlog ($m)	2017	2018	2019	2020	2021
Ultra-deepwater	8,383	7,063	5,796	4,793	3,845
Deepwater	121	0	0	0	0
Harsh-environment	385	37	0	0	0
Midwater	88	15	0	0	0
Jackups	57	0	0	0	0
Total backlog	**9,034**	**7,116**	**5,796**	**4,793**	**3,845**

	2017	2018	2019
Total debt	7,148	6,717	6,689
Debt / YE backlog	**0.8**	**0.9**	**1.2**

Backlog by customer ($m	#1	#2	#3	#4	#5
Ultra-deepwater	**RDS**	**CVX**	**PBR**	**BP**	**BHP**
Backlog	6,831	1,473	365	55	38
% of backlog	77%	17%	4%	1%	0%
Deepwater	**PBR**	**ONGC**			
Backlog	109	51			
% of backlog	68%	32%			
Harsh-environment	**Enq**	**STO**	**SU**	**HSE**	**Mgmt**
Backlog	184	140	100	68	27
% of backlog	34%	26%	19%	13%	5%
Midwater	**ONGC**	**Fairfield**			
Backlog	62	55			
% of backlog	53%	47%			
Jackups	**CVX**				
Backlog	84				
% of backlog	100%				

Top 5 customers in backlog		Percent	$bn
RDS	#1	70%	6.8
CVX	#2	16%	1.6
PBR	#3	5%	0.5
Enq	#4	2%	0.2
STO	#5	1%	0.1
Other		**5%**	**0.5**

Fleet composition	2017	2018	2019
Ultra-deepwater	25	27	28
Deepwater	2	2	2
Harsh-environment	7	7	7
Midwater	4	4	4
Jackups	2	2	2
Total in fleet	**40**	**42**	**43**

Source: Company reports, Deutsche Bank

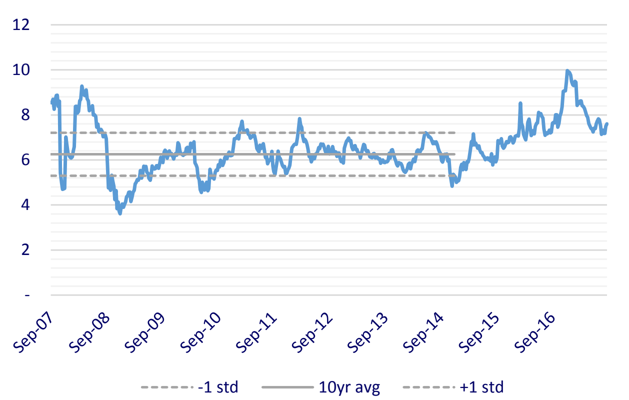
Valuation and risks

We are initiating coverage of Transocean with an $13 price target. This is 5.0x our estimate of the company's normalized EBITDA of $1.8 billion, which is one-turn below the 6.0x five-year average multiple of 6.0x. The company is currently trading at 8.3x our fiscal 2018 EBITDA estimate of $1 billion. We believe the discounted multiple is warranted due to the severely diminished earnings power of the company and the significant challenges that lie ahead for the industry in terms of utilization and pricing power as the deepwater market copes with the historic supply demand imbalance.

In terms of steel value, we assess the trough net asset value at $4.35 per share, which assumes the market endures another three years of high volumes of cold-stacking once contracts expire and leading edge market rates that stay at breakeven levels ($160-170 kpd).

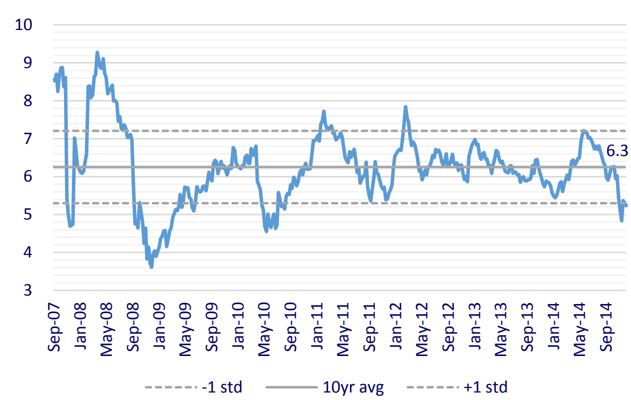
The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) more M&A with Transocean as the suitor, and 4) increased flow of capex directed away from the offshore and toward onshore operations. Upside risks are mainly associated with a rapid rise in oil prices, which would prompt the firmly entrenched sentiment in the offshore drilling names to pivot in our view.

Figure 606: The EV/EBITDA valuation band as blown out



Source: Factset

Figure 607: The 5yr EV/EBITDA leading up to 2014

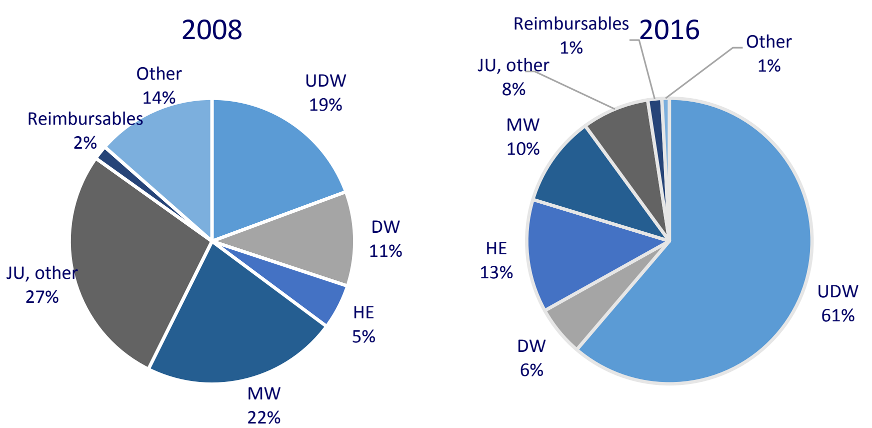


Source: Factset

Company description

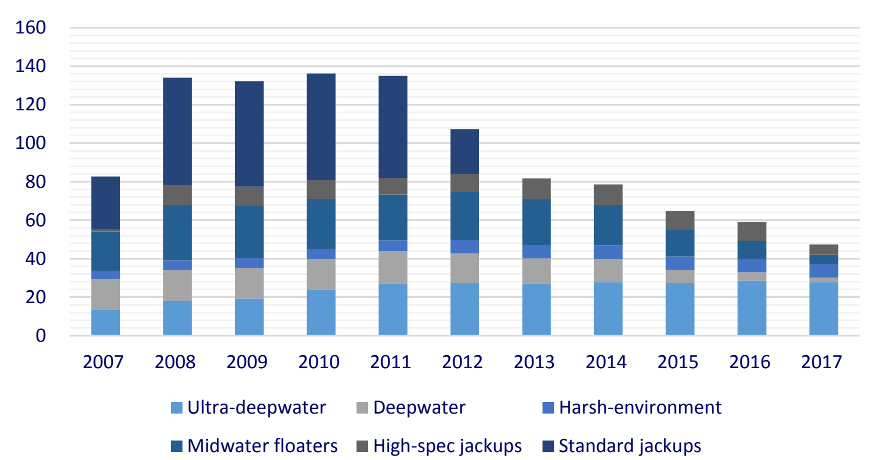
Transocean (RIG) is a contract drilling company with a fleet of 42 mobile offshore drilling rigs including 29 ultra-deepwater floaters (four are currently under construction), seven harsh environment floaters, two deepwater floaters, and four midwater floaters. Until recently, the company had 15 jackups, which were sold to Borr Drilling for a total consideration of $1.35 billion. The company also recently announced the planned acquisition of Songa Offshore for a total consideration of $3.4 billion. Songa Offshore has seven semis in Norway including four active harsh environment semis with a backlog of $4.1 billion..

Figure 608: Revenues by rig type



Note: UDW = ultra-deepwater, DW = deepwater, HE = harsh environment, MW = midwater, JU = jackup.
Source: Company reports, Deutsche Bank

Figure 609: Change in fleet size and mix (excludes Songa Offshore)



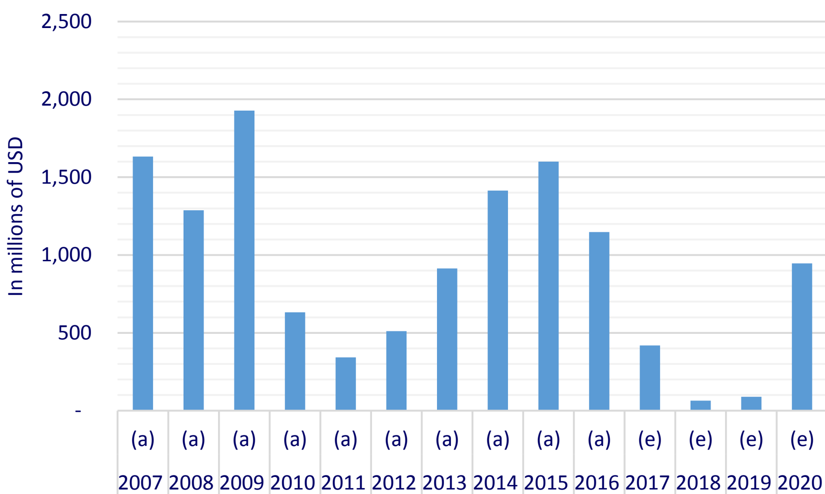
Source: Company reports

Principal Sources and Uses of Cash Flow

Executing a strategy to be top ultra-deep and harsh environment driller

The ultra-deepwater (UDW) segment is Transocean's largest and accounted for 60% of 2016 revenues. RIG has invested heavily in the UDW, totaling $13 billion from 2007 through 2020 when the company currently plans to take delivery of its last remaining two drillships. The company delivered 14 UDW rigs as part of this program to-date with another two fully contracted units coming online in the coming six months.

Figure 610: RIG's ultra-deepwater newbuild capex since 2007 totals $13 billion



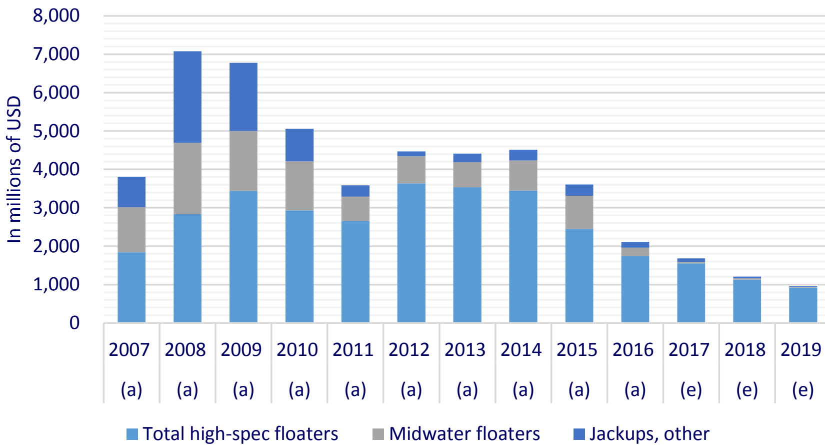
Source: Company reports, Deutsche Bank

The deepwater (DW) segment has seen its share of the company revenues fall considerably during the downturn and accounted for just 6% of overall revenue in 2016. The segment includes many 5th generation floaters which have a difficult time competing as they do not carry the same efficiency as the newest (6th) generation units, yet are more expensive to operate than the older, midwater units. RIG elected to retire a number of DW rigs during the downturn as they could not compete with more capable units that were also available.

The harsh environment segment has proved very resilient during the downturn and accounted for 13% of 2016 revenues. The harsh environment has some of the best market trends in the offshore sector in our view and is the least over-supplied among all the offshore drilling segments.

The midwater segment has been hit the hardest during the downturn. The midwater fleet includes five of the company's oldest rigs, two of which are currently cold-stacked. RIG elected to scrap a number of midwater rigs as these units are older and not viable assets going forward.

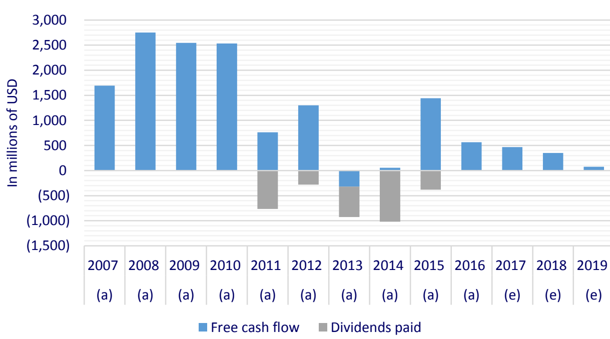
Figure 611: Segment EBITDA peaked in 2008



Source: Company reports, Deutsche Bank

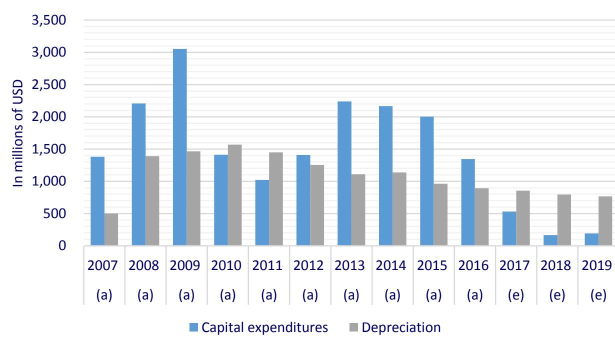
Transocean's high water mark was in 2008 when it posted about $7 billion of EBITDA. We estimate its earnings power has eroded to about $2 billion assuming ultra-deepwater rigs regain about $300 kpd of dayrate in 2020 and beyond. Pro-forma for the Songa Offshore deal, we estimate its power to be about $2.4 billion of EBITDA.

Figure 612: Free cash flow and dividends



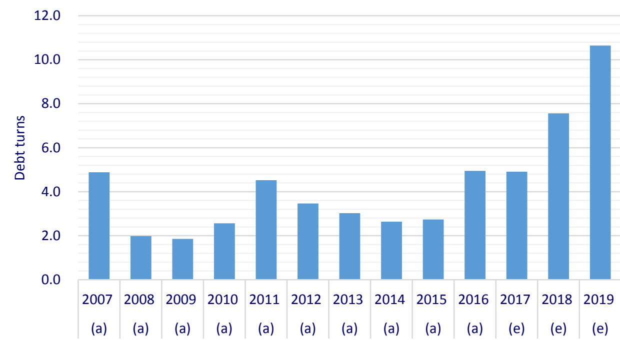
Source: Company reports, Deutsche Bank

Figure 613: Capex trend



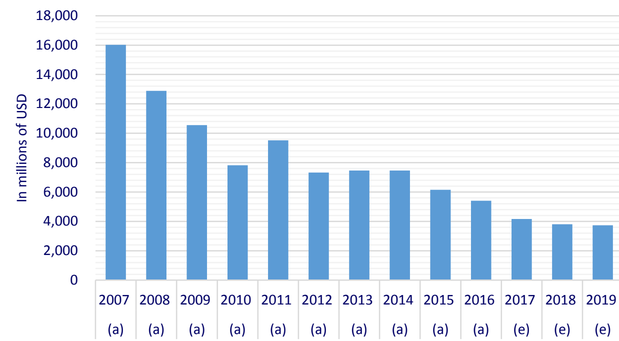
Source: Company reports, Deutsche Bank

Figure 614: Debt turns



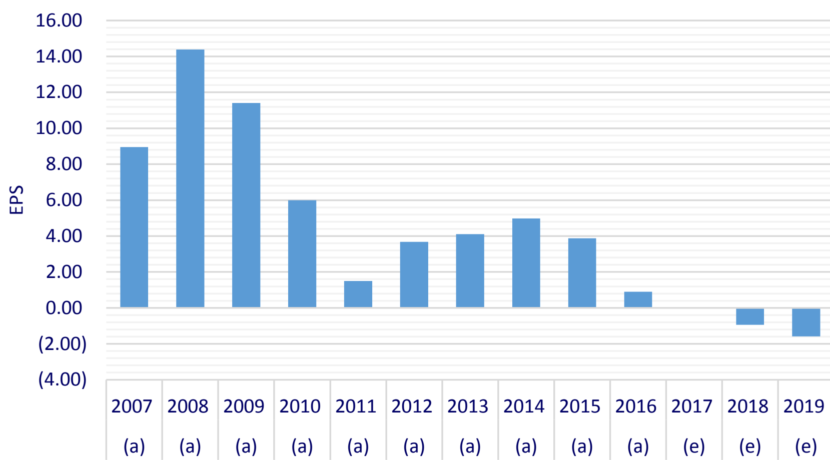
Source: Company reports, Deutsche Bank

Figure 615: Net debt



Source: Company reports, Deutsche Bank

Figure 616: EPS trend



Source: Company reports, Deutsche Bank

Figure 617: Fleet profile

Rig name	Water depth (ft)	Rig type	Year in service	Rig design	Backlog (yrs)	Backlog ($m)
Ultra-deepwater (34):						
Deepwater Asgard	12,000	DS-DP	2014	Daewoo (DSME) 12000	-	-
Deepwater Invictus	12,000	DS-DP	2014	Daewoo (DSME) 12000	0.2	38.5
Deepwater Pontus	12,000	DS-DP	2017	Daewoo (DSME) 12000	10.0	1,895.4
Deepwater Poseidon	12,000	DS-DP	2017	Daewoo (DSME) 12000	10.0	1,894.4
Deepwater Proteus	12,000	DS-DP	2016	Daewoo (DSME) 12000	8.7	1,540.1
Deepwater Thalassa	12,000	DS-DP	2016	Daewoo (DSME) 12000	8.4	1,501.6
Deepwater Conqueror	12,000	DS-DP	2016	Daewoo (DSME) 12000	4.3	912.4
Transocean Drsh Tbn1	12,000	DS-DP	2020	Jurong Shipyard Limited Jurong Espadon III	-	-
Transocean Drsh Tbn2	12,000	DS-DP	2020	Jurong Shipyard Limited Jurong Espadon III	-	-
Discoverer Americas	12,000	DS-DP	2009	Transocean Enhanced Enterprise Class	-	-
Deepwater Champion	12,000	DS-DP	2010	GustoMSC P10000	-	-
Discoverer Clear Leade	12,000	DS-DP	2009	Transocean Enhanced Enterprise Class	0.2	37.4
Discoverer Inspiration	12,000	DS-DP	2009	Transocean Enhanced Enterprise Class	2.5	523.6
Dhirubhai Deepwater	12,000	DS-DP	2009	Samsung/Saipem Saipem 10000	0.3	39.8
Dhirubhai Deepwater	12,000	DS-DP	2009	Samsung/Saipem Saipem 10000	0.3	24.0
Discoverer India	12,000	DS-DP	2010	Transocean Enhanced Enterprise Class	-	-
Petrobras 10000	12,000	DS-DP	2009	Samsung 10000	1.9	325.1
Discoverer Deep Seas	10,000	DS-DP	2001	Transocean Offshore Discoverer Class Enhanced	-	-
Discoverer Enterprise	10,000	DS-DP	1999	Transocean Offshore Discoverer Class Enhanced	-	-
Discoverer Spirit	10,000	DS-DP	2000	Transocean Offshore Discoverer Class Enhanced	-	-
GSF C.R. Luigs	10,000	DS-DP	2000	Global Marine Glomar 456 Class	-	-
GSF Jack Ryan	10,000	DS-DP	2000	Global Marine Glomar 456 Class	Retired in Sep-17	
Deepwater Discovery	10,000	DS-DP	2000	Samsung/Reading & Bates Deepwater Pathfinder	-	-
Deepwater Frontier	10,000	DS-DP	1999	Samsung/Reading & Bates Deepwater Pathfinder	-	-
Deepwater Millenniun	10,000	DS-DP	1999	Samsung/Reading & Bates Deepwater Pathfinder	-	-
Deepwater Pathfinder	10,000	DS-DP	1998	Samsung/Reading & Bates Deepwater Pathfinder	Retired in Sep-17	
Cajun Express	8,500	5th	2001	Sedco Forex SFXpress 2000	Retired in Sep-17	
Deepwater Nautilus	8,000	5th	2000	Reading & Bates RBS-8M	-	-
Discoverer Luanda	7,500	DS-DP	2010	Transocean Enhanced Enterprise Class	0.3	54.7
GSF Development Drill	7,500	6th	2005	Friede & Goldman ExD	0.9	29.8
GSF Development Drill	7,500	6th	2005	Friede & Goldman ExD	-	-
Development Driller III	7,500	6th	2009	KFELS/MSC DSS 51	0.0	0.7
Sedco Energy	7,500	5th	2001	Sedco Forex SFXpress 2000	Retired in Sep-17	
Sedco Express	7,500	5th	2001	Sedco Forex SFXpress 2000	Retired in Sep-17	
Deepwater (3):						
Transocean Marianas	7,000	4th	1998	Earl & Wright/Sedco 700 Series Enhanced	Retired in Sep-17	
Sedco 706	6,562	2nd	1976	Earl & Wright/Sedco 700 Series	1.1	109.2
Jack Bates	5,400	4th	1986	Friede & Goldman L-1020 Trendsetter	1.1	50.8
Harsh-Environment (7):						
Transocean Barents	10,000	6th	2009	Aker H-6e	1.1	99.8
Transocean Spitsberge	10,000	6th	2010	Aker H-6e	1.1	140.0
Henry Goodrich	2,000	4th	1985	Mitsui/Sonat SES-5000	0.7	67.9
Transocean Leader	4,500	4th	1987	Aker H-4.2	1.6	184.0
Paul B. Loyd, Jr.	2,000	4th	1987	Aker H-4.2	0.2	16.3
Transocean Arctic	1,640	4th	1986	Marotec/Ross Marosso 56	0.4	27.1
Polar Pioneer	1,476	4th	1985	Sonat Offshore/Hitachi	-	-
Midwater (4):						
Sedco 711	1,800	3rd	1982	Earl & Wright/Sedco 711 Series	-	-
Sedco 712	1,600	3rd	1983	Earl & Wright/Sedco 711 Series	0.8	55.4
Sedco 714	1,600	3rd	1983	Earl & Wright/Sedco 711 Series	-	-
Actinia	1,500	3rd	1982	Friede & Goldman L-1033 Enhanced Pacesetter	1.7	61.8

Source: Company reports, Deutsche Bank

Figure 618: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
Ultra-deepwater	2,997	3,170	3,945	4,644	4,523	4,496	3,366	2,317	1,958	1,760	1,756
Deepwater	1,731	1,461	974	1,145	1,143	1,021	644	214	143	127	73
Harsh-environment	613	675	806	986	1,150	1,099	891	484	519	490	379
Total high-spec floaters	**5,341**	**5,306**	**5,725**	**6,775**	**6,816**	**6,616**	**4,901**	**3,015**	**2,620**	**2,377**	**2,208**
Midwater	2,507	2,092	1,461	1,572	1,658	1,722	1,359	388	83	85	67
Jackups, other	2,758	1,569	1,149	800	582	598	526	288	164	81	58
Reimbursables	193	152	161	175	168	173	138	60	28	25	23
Other revenue	757	457	646	350	260	65	95	32	97	40	40
Total revenue	11,556	9,576	9,142	9,672	9,484	9,174	7,019	3,783	2,992	2,608	2,396
Segment EBITDA:											
Ultra-deepwater	-	-	2,011	2,870	2,450	2,483	1,657	1,412	1,227	823	779
Deepwater	-	-	186	368	392	474	335	80	65	57	4
Harsh-environment	-	-	464	398	690	492	459	249	262	245	133
Total high-spec floaters	**3,438**	**2,930**	**2,660**	**3,636**	**3,532**	**3,449**	**2,451**	**1,741**	**1,555**	**1,125**	**917**
Midwater floaters	1,562	1,283	632	705	657	786	862	217	31	38	19
Jackups, other	1,774	847	291	130	220	278	298	153	98	45	21
Drilling and non-drilling	(250)	(439)	(317)	(594)	(596)	(449)	(334)	(240)	(74)	(160)	(168)
Corporate	(194)	(240)	(271)	(281)	(276)	(238)	(176)	(160)	(154)	(160)	(160)
EBITDA	6,330	4,381	2,995	3,597	3,538	3,826	3,100	1,711	1,455	888	629
D&A	1,464	1,568	1,449	1,254	1,109	1,139	963	893	855	794	768
EBIT	4,866	2,813	1,546	2,343	2,429	2,687	2,137	818	600	94	(139)
Interest (expense)	(484)	(567)	(621)	(723)	(584)	(483)	(432)	(409)	(511)	(530)	(583)
Interest income	5	23	44	56	52	39	22	20	27	25	27
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	(19)	14	(9)	(40)	(26)	(6)	26	37	(3)	(8)	(8)
PBT	4,368	2,283	960	1,636	1,871	2,237	1,753	466	112	(419)	(703)
Income tax (expense)	(699)	(327)	(385)	(306)	(383)	(406)	(300)	(86)	(84)	50	84
Non-controlling interest	11	(27)	(93)	(21)	0	(21)	(35)	(46)	(15)	0	0
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	3,680	1,929	481	1,309	1,488	1,810	1,418	333	13	(369)	(619)
Discontinued ops	0	0	141	(863)	1	(20)	2	0	0	0	0
Unusual after-tax	(499)	(969)	(6,347)	(633)	(84)	(3,703)	(629)	447	(1,604)	0	0
Net income (GAAP)	3,181	960	(5,725)	(188)	1,404	(1,913)	792	781	(1,591)	(369)	(619)
Operating EPS	11.40	6.00	1.49	3.68	4.11	4.98	3.88	0.91	0.03	(0.94)	(1.58)
GAAP EPS	9.85	2.97	(17.77)	(0.53)	3.88	(5.31)	2.15	2.12	(4.07)	(0.94)	(1.58)
DPS	0.00	0.00	2.36	0.79	1.68	2.81	1.05	0.00	0.00	0.00	0.00
Diluted shares	321	320	322	356	361	362	364	368	391	391	391
EBITDA margin	54.8%	45.7%	32.8%	37.2%	37.3%	41.7%	44.2%	45.2%	48.6%	34.0%	26.2%
EBIT margin	42.1%	29.4%	16.9%	24.2%	25.6%	29.3%	30.4%	21.6%	20.1%	3.6%	-5.8%
Tax rate	16.0%	14.3%	40.2%	18.7%	20.5%	18.1%	17.1%	18.6%	74.9%	12.0%	12.0%
Utilization:											
Ultra-deepwater	92%	79%	80%	89%	92%	82%	66%	45%	44%	57%	60%
Deepwater	86%	65%	44%	58%	68%	62%	73%	54%	80%	97%	95%
Harsh-environment	89%	92%	88%	85%	100%	85%	64%	58%	76%	83%	82%
Midwater floaters	79%	69%	56%	61%	61%	64%	77%	42%	37%	49%	48%
Dayrates:											
Ultra-deepwater	463	457	500	525	500	539	514	492	446	311	297
Deepwater	345	385	362	356	353	378	354	254	196	179	106
Harsh-environment	378	402	436	450	452	507	543	329	269	230	182
Midwater floaters	323	320	299	278	311	347	349	274	123	120	96

Source: Deutsche Bank

Figure 619: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Net income	3,680	1,929	481	1,309	1,488	1,810	1,418	333	13	(369)	(619)	(865)
Depreciation	1,464	1,568	1,449	1,254	1,109	1,139	963	893	855	794	768	768
Deferred tax	13	(145)	(31)	(133)	(9)	(142)	(78)	68	(39)	0	0	0
Chg in receivables	504	386	(174)	(139)	58	97	741	481	336	123	31	32
Chg in inventories	0	0	0	0	0	(50)	183	74	75	42	72	69
Chg in payables	(60)	227	978	931	(625)	(147)	(336)	(242)	(26)	22	6	0
Other	(3)	(19)	(918)	(514)	(103)	(487)	554	304	(214)	(98)	9	5
Cash from operations	5,598	3,946	1,785	2,708	1,918	2,220	3,445	1,911	1,001	514	266	9
Capital expenditures	(3,052)	(1,411)	(1,020)	(1,409)	(2,238)	(2,165)	(2,001)	(1,344)	(533)	(165)	(190)	(1,072)
Free cash flow	2,546	2,535	765	1,299	(320)	55	1,444	567	468	349	76	(1,063)
Acquisitions	0	0	(1,246)	0	0	0	0	0	0	0	0	0
Asset sales	18	60	461	980	378	250	54	30	329	0	0	0
Dividends paid	0	0	(763)	(278)	(606)	(1,018)	(381)	0	0	0	0	0
ESPP | options	19	0	0	0	0	0	0	0	0	0	0	0
Equity issuance, net	0	(240)	1,211	0	0	0	0	0	0	0	0	0
Debt issuance, net	(2,739)	(704)	442	(1,049)	(1,692)	(539)	(1,506)	106	(1,372)	(431)	(28)	(327)
Other	28	575	(247)	165	349	644	93	10	512	0	0	0
Chg in cash	(128)	2,226	623	1,117	(1,891)	(608)	(296)	713	(63)	(82)	48	(1,390)
FCF per share	7.93	7.92	2.37	3.65	(0.89)	0.15	3.97	1.54	1.20	0.89	0.20	(2.72)
Capex / revenue	0.26	0.15	0.11	0.15	0.24	0.24	0.29	0.36	0.18	0.06	0.08	0.49
Capex / depreciation	2.08	0.90	0.70	1.12	2.02	1.90	2.08	1.51	0.62	0.21	0.25	1.40

Source: Deutsche Bank

Figure 620: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	1,168	3,394	4,017	5,134	3,243	2,635	2,339	3,052	2,989	2,907	2,955
Accounts receivable	2,385	2,000	2,176	2,200	2,112	2,120	1,379	898	562	440	409
Inventories	462	517	529	610	743	818	635	561	486	444	373
Deferred taxes	104	115	142	142	151	161	0	0	0	0	0
Other current assets	357	169	672	561	523	267	432	587	131	114	106
Total current assets	4,476	6,195	7,536	8,647	6,772	6,001	4,785	5,098	4,169	3,904	3,843
Net PP&E	23,018	21,458	20,788	20,880	21,707	21,538	20,818	21,093	18,771	18,142	17,564
Goodwill	8,134	8,132	3,217	2,987	2,987	0	0	0	0	0	0
Other assets	808	1,026	3,491	1,741	1,080	874	726	698	632	547	509
Total assets	36,436	36,811	35,032	34,255	32,546	28,413	26,329	26,889	23,572	22,593	21,916
Accounts payable	780	847	880	1,047	1,106	784	448	206	180	202	208
Accrued expenses	240	116	86	116	53	131	82	95	66	57	53
Current debt	1,868	2,012	2,187	1,367	323	1,033	1,093	724	713	310	609
Other current liabilities	730	861	2,375	2,933	2,072	1,822	1,046	960	720	622	579
Total current liabilities	3,618	3,836	5,528	5,463	3,554	3,770	2,669	1,985	1,679	1,192	1,449
Long-term debt	9,849	9,209	11,349	11,092	10,379	9,059	7,397	7,740	6,435	6,407	6,080
Deferred taxes	726	594	487	366	374	237	339	178	155	155	155
Other LT liabilities	1,684	1,772	1,925	1,604	1,554	1,354	1,108	1,153	1,014	877	816
Non-controlling int	7	8	106	(15)	(6)	311	310	3	4	4	4
Shareholders' equity	20,552	21,392	15,637	15,745	16,691	13,682	14,506	15,830	14,286	13,959	13,411
Total liabilities and equity	36,436	36,811	35,032	34,255	32,546	28,413	26,329	26,889	23,572	22,593	21,916
Total debt	11,717	11,221	13,536	12,459	10,702	10,092	8,490	8,464	7,148	6,717	6,689
Net debt	10,549	7,827	9,519	7,325	7,459	7,457	6,151	5,412	4,159	3,810	3,733
Debt/capital	36%	34%	46%	44%	39%	42%	37%	35%	33%	32%	33%
Debt/equity	57%	52%	87%	79%	64%	74%	59%	53%	50%	48%	50%
Debt turns	**1.9**	**2.6**	**4.5**	**3.5**	**3.0**	**2.6**	**2.7**	**4.9**	**4.9**	**7.6**	**10.6**

Source: Deutsche Bank

Rating
Buy

North America
United States

Industrials
Oil Services & Equipment

Company
Weatherford International

Reuters	Bloomberg
WFT.N	WFT US

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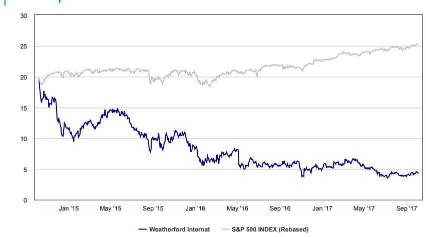
Price at 5 Oct 2017 (USD)	4.27
Price target	6.00
52-week range	6.65 - 3.53

Price/price relative



Performance (%)	1m	3m	12m
Absolute	6.5	6.8	-20.0
S&P 500 INDEX	2.5	4.5	18.0

Source: Deutsche Bank

Stock & option liquidity data

Market Cap (USDm)	4,225.2
Shares outstanding (m)	989.5
Free float (%)	99
Volume (5 Oct 2017)	4,067,693
Option volume (und. shrs., 1M avg.)	1,429,321

Source: Deutsche Bank

New CEO, New Process and Culture

Initiating coverage with a Buy rating and a $6 price target

The change in leadership, the acknowledgement of systematic problems, and the plan to fix them offer idiosyncratic upside as most of the oilfield faces off with the macro uncertainties. The call on WFT has always been more complex than earnings growth and near-term credit concerns. There has been a systematic issue at WFT dating into the late 1990s as it gobbled up acquisition targets in pursuit of growth, but with disregard for process and efficiency. As CEO Mark McCollum completes his strategic review, we expect a new discipline that will elevate WFT from last among 30 oilfield service companies in terms of cash conversion, which should deliver positive free cash flow and reduce credit concerns. While we see a path to getting there, the interim risks to capital raises versus asset sales is still high.

Weatherford can pivot its history of negative free cash flow

While companies with meaningful international exposure tend to have lower cash conversions (CFO/EBITDA), WFT has ranked dead last over the last ten years versus 30 other oilfield service companies. WFT averaged just $0.31 of cash flow from operations for every dollar of EBITDA, which was less than half that of Halliburton ($0.67) and almost two-thirds less than Schlumberger ($0.78). A significantly inefficient cost structure, poor working capital management, and an acquisition strategy that went awry all contributed, but there are fixes that the new leadership can implement.

Deep cultural turnaround for a company that was lacking process

This will not be easy and it will not happen quickly, but we like the potential for the new leadership to extract and apply best practices to WFT. The new CEO has identified upwards of $600 million more in cost reductions, is realistic about what needs to happen to sell the international land drilling business, and is focused on $500+ million in working capital inefficiencies.

Valuation

Our $6 price target is 8.0x our estimate of the company's normalized EBITDA power of $1.45 billion, which is a half-turn premium to the 7.5x five-year average multiple leading up to the 2014 collapse in oil prices. A rehabilitation of its cash conversion metrics should in our view provide small multiple expansion as the company is enabled to generate positive free cash flow.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an equity raise to reduce debt, and 4) a derailing of its efforts to reduce working capital intensity and net debt.

Forecasts and ratios

Year End Dec 31	2016A	2017E	2018E
1Q EPS	-0.29	-0.32A	-0.12
2Q EPS	-0.28	-0.25A	-0.08
3Q EPS	-0.39	-0.24	-0.05
4Q EPS	-0.32	-0.20	-0.03
FY EPS (USD)	-1.29	-1.01	-0.28
OLD FY EPS (USD)	-1.29	–	–
% Change	-0.0%	–	–
P/E (x)	–	–	–
DPS (USD)	0.00	0.00	0.00
Dividend Yield (%)	0.0	0.0	0.0
Revenue (USDm)	5,749.0	5,764.4	6,205.1

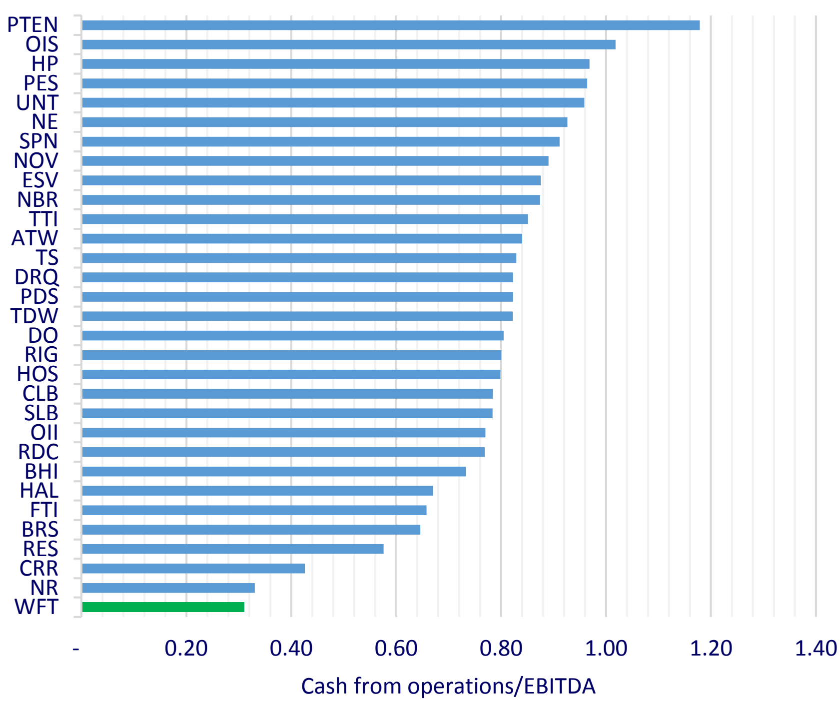
Source: Deutsche Bank estimates, company data

Key investment themes

Line of sight to the end of chronic underperformance in cash conversion

Weatherford had for longtime been seen as the high-torque oil-play with high earnings leverage enabled by an active acquisition strategy. Unfortunately, the outcome was chronic underperformance in generating free cash flow which scored WFT last place in a ten-year cash conversion comparison with 30 of its oilfield service peers. There is an idiosyncratic opportunity embedded in WFT for the new leadership to elevate its cash conversion by monetizing its inventories, reducing receivable days, reducing redundant costs and most importantly, creating a new culture and process.

Figure 621: Average ten year cash conversion ratio…WFT is last

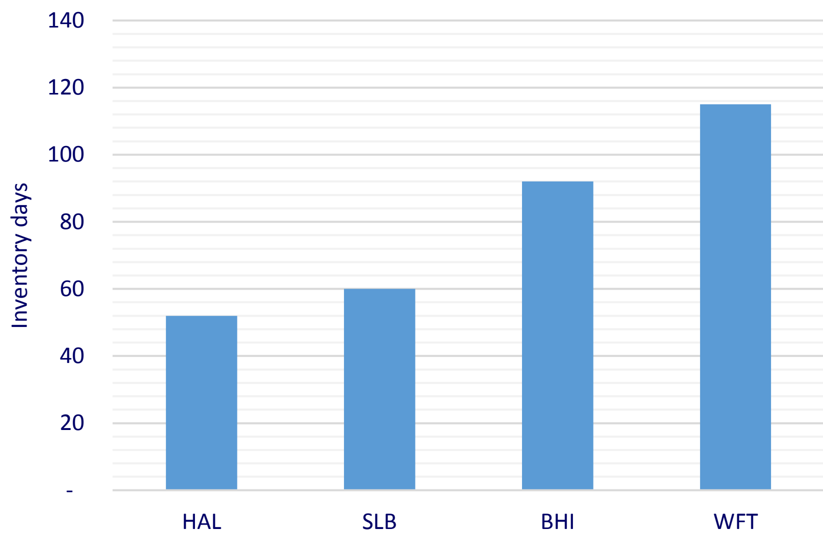


Source: Deutsche Bank

Working capital efficiencies of $500 – 700 million targeted, but will take time

A glaring difference between Weatherford and its peers are its inventory days. Weatherford over the last ten years has averaged 115 days of inventory versus Halliburton and Schlumberger down at 52 and 60 days respectively. WFT needs to monetize its inventories better and that is what management intends to do. This will take time, but if management could reduce inventory days to where BHGE has averaged over the past ten years (92 days), that would unlock $0.5 billion in cash. Unrealistic to compare to Schlumberger and Halliburton, but getting down to their level would unlock $1 billion in cash from Working capital.

Figure 622: Ten year average inventory days…WFT underperforming

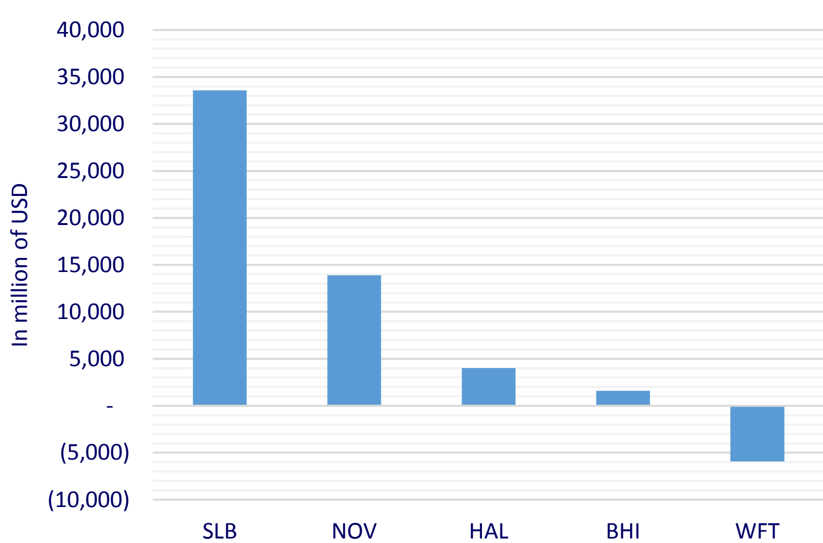


Source: Company reports, Deutsche Bank

Still room to reduce more costs by upwards of $600 million

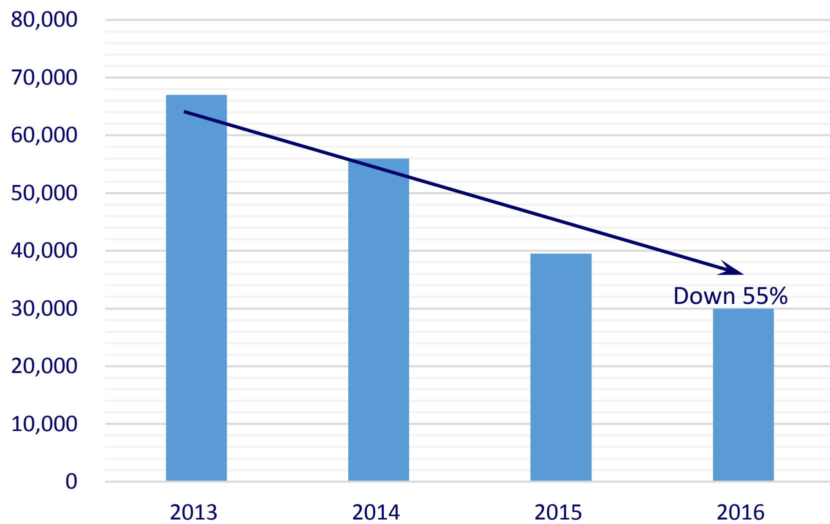
As Mark McCollum works through his strategic review, there have been upwards of $600 million of additional cost cuts identified including the closure of some redundant facilities.

Figure 623: Cumulative free cash flow over last ten years



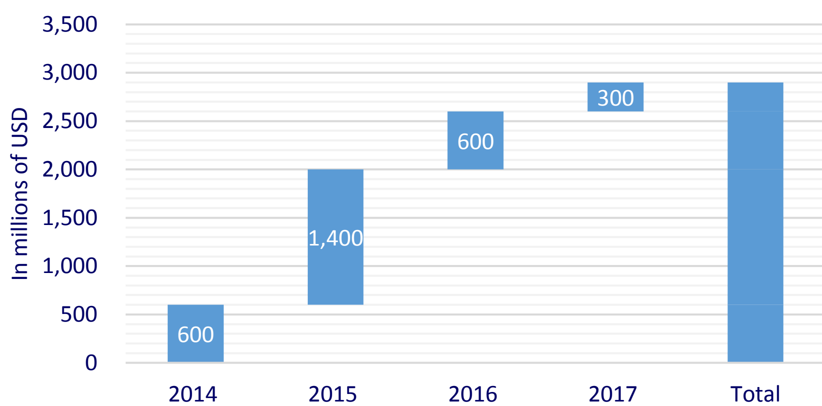
Source: Company reports, Deutsche Bank

Figure 624: Weatherford has reduced headcount by 55% since 2013



Source: Company reports, Deutsche Bank

Figure 625: Annual cost reductions since 2014 with another $600m coming



Source: Company reports, Deutsche Bank

Core to the strategy is delivering the balance sheet

Debt reduction is at the top of the list. Weatherford's annual interest expense is 10% of revenues compared to 2.5% for Halliburton and 1.6% for Schlumberger. Management's goal is to cut its $7.1 billion of net debt in half by year-end 2019. The path to get there includes:

- $535 million from the OneStim joint venture by year-end 2017
- Sale of international land rig business for $500 – 1,000 million
- Additional cost cutting totaling upwards of $500 – 600 million
- Working capital efficiencies of $500 – 600 million
- $540 million from any exercise of warrants at $6.43 per share

Market willing, the sale of the international land rig business is a key component and a key unknown still. Management is now willing to sell the segment in pieces instead of only considering the whole, which could accelerate the process that began just before oil prices dropped in 2014. WFT's expectation is about $500 – 1,000 million. We would suggest the lower end of the range as the most realistic. The additional cost cutting we expect to be implemented in 2018, but the working capital efficiencies will take time to normalize, albeit not at peer levels realistically, and probably through 2019.

Valuation and risks

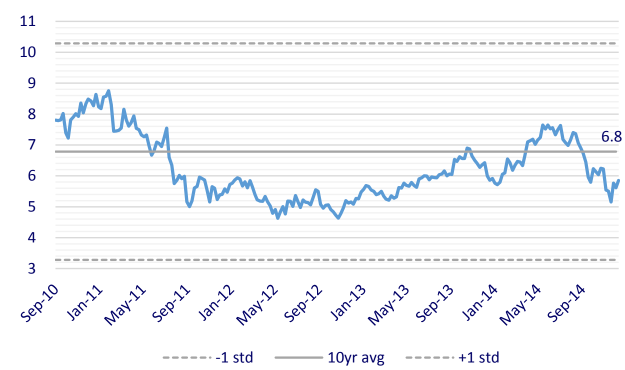
Our $6 price target is 8.0x our estimate of the company's normalized EBITDA power of $1.45 billion, which is a half-turn premium with the five-year average multiple leading up to the 2014 collapse in oil prices. A rehabilitation of its cash conversion metrics should in our view provide small multiple expansion as the company is enabled to generate positive free cash flow.

The main investment risks include: 1) shifts in OPEC policy and the influence that would have on oil prices and ultimately US upstream capital expenditures, 2) negative revisions to global oil demand, 3) an equity raise to reduce debt, and 4) a derailing of its efforts to reduce working capital intensity and net debt.

Figure 626: The P/E valuation band as blown out

Source: Factset

Figure 627: The 5yr P/E leading up to 2014



Source: Factset

Company description

Weatherford International (WFT) is a diversified oilfield services company with operations in 90 countries. Approximately 26% of its revenues were in the US in 2016 versus 37% at the industry peak in 2014. Canada was about 7% of revenues in 2016 with Latin America contributing 19% and the eastern hemisphere contributing about 52%. The company is currently organized under five operating divisions including Drilling and Formation Evaluation, Well Construction, Completion and Stimulation, Production, and Land Drilling (currently up for sale). Its core strengths and leadership markets are managed pressure drilling (MPD), tubular running services (TRS), fishing and rentals, artificial lift, and completions.

In early 2017, Weatherford and Schlumberger announced the formation of a JV that will deliver completion products and services for the development of unconventional resources in North America. Schlumberger and Weatherford will have a 70/30 ownership in the JV. Weatherford will contribute its multi-stage completions portfolio including its 20 US frac spreads with about 1 million horsepower. Upon closing of the JV agreement by year-end 2017, WFT will receive $535 million in cash from Schlumberger.

Figure 628: Operating divisions

Weatherford International

Drilling and Formation Evaluation
- Managed Pressure Drilling (MPD)
- Drilling Services
  - Directional Drilling
  - Measurement-while-drilling (MWD)
  - Logging-while-drilling (LWD)
  - Rotary steerable systems (RSS)
- Wireline Services
  - Open-hole and cased-hole services
  - Well intervention and remediation
- Testing and Production Services
- Laboratory Services (core analysis)
- Surface Logging Systems

Land Drilling - 110 rigs
- Middle East - 47%
- Latin America - 22%
- North Africa - 16%
- Asia Pacific - 12%
- Europe - 3%

Well Construction
- Tubular Running Services (TRS)
- Drilling Tools and Rental Equipment
- Re-entry and Fishing Services
- Cementing Products
- Liner Systems
- Solid Expandable Systems

Completion and Stimulation
- OneStim JV with Schlumberger (30/70)
  - Hydraulic fracturing
  - Multistage completions
  - Pump down perforating

Production
- Artificial Lift Systems
- Flow Measurements
- Production and Reservoir Monitoring
- Pump and Fluid Systems

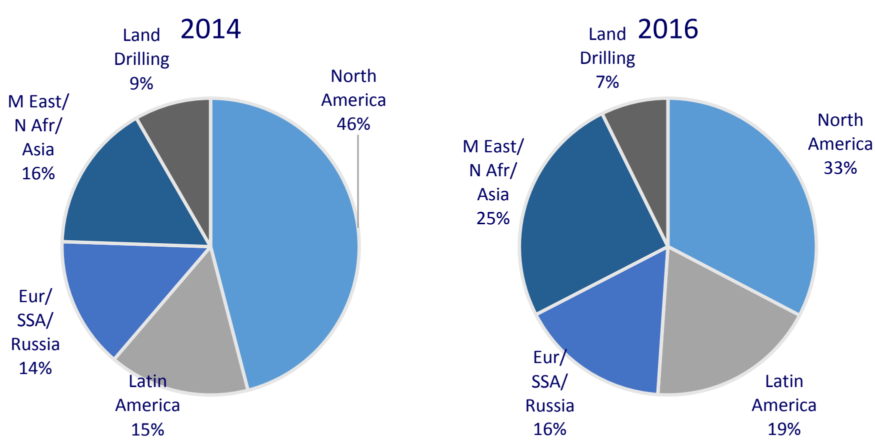
Source: Company reports

Principal Sources and Uses of Cash Flow

Acquisition strategy a primary source of earnings growth

Weatherford has a diversified revenue stream with North America contributing 33% of 2016 revenues followed by the Middle East/ North Africa/ Asia Pacific region contributing 23%. In general, when thinking about WFT compared to its peers, the company has more onshore exposure and has more Canadian exposure, with the latter impacting Q2 results due to the spring breakup seasonality. The company's land drilling and workover rig fleet, which is for sale, is concentrated in the Middle East and North Africa.

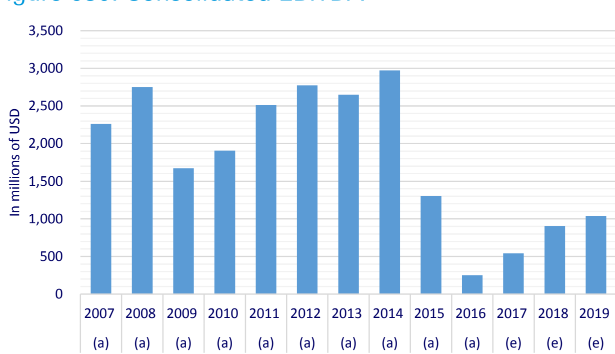
Figure 629: Geographic segment revenues



Source: Company reports, Deutsche Bank

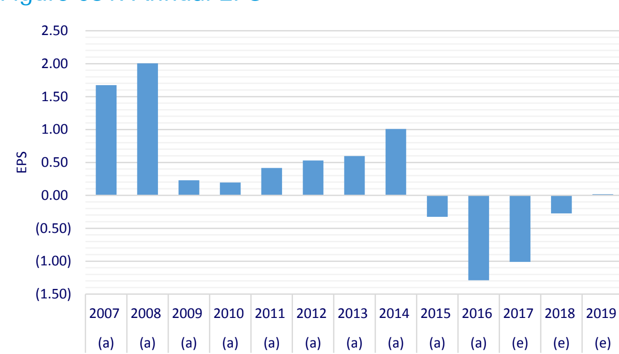
WFT has grown organically and via acquisitions (more than 200) over the course of its history. The former CEO was a builder, using acquisitions to fill in product line gaps and global footprint to compete with the diversified players. In its history while aggressively pursuing this growth, the focus would shift from profitability and cost control to revenue and market share. The new CEO, Mark McCollum, wants to improve execution and profitability, and create a culture and a process that lends to returns rather than just market share.

Figure 630: Consolidated EBITDA



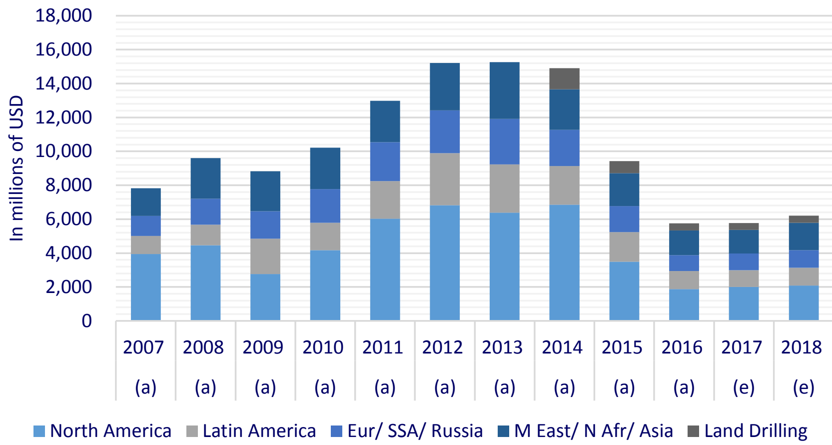
Source: Company reports, Deutsche Bank

Figure 631: Annual EPS



Source: Company reports, Deutsche Bank

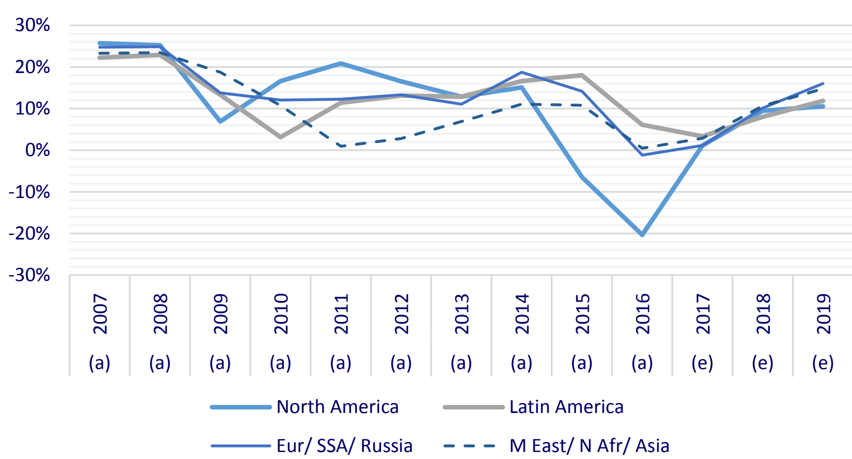
Figure 632: Geographic revenue mix



Source: Company reports, Deutsche Bank

North America margins have lagged competitors in recent quarters as WFT's pressure pumping business underperformed and the company was impacted by declining activity in the Gulf of Mexico and higher costs to return equipment into the field. Its underperforming pressure pumping operations always seemed to lack the necessary scale and it was contributed to the OneStim JV. Its International business continues to be impacted by project delays and pricing pressures, but the company has been able to partially offset some of this by incremental cost savings from their restructuring efforts. WFT is also expects to benefit from recent contract wins in the Middle East as these projects start to ramp up in the coming quarters.

Figure 633: EBIT margins



Source: Company reports, Deutsche Bank

WFT exposure is slightly different than some of its larger peers, but the company still competes against them across several product lines. Their main competitors across the globe are SLB, HAL, and BHGE. WFT also competes against large companies across distinct segments of its business including NOV, NBR, and FI.

There are also regional competitors that are focused on a specific market or a limited range of equipment and services offerings. To be more

specific around its core product lines, in artificial lift WFT is a top three player with SLB and BHGE. In tubular running services, WFT is a top two player sharing essentially a global duopoly with FI. In completion equipment, WFT is also a top 3 player with the large diversified peers being the biggest players in that market. In rentals, WFT is the largest player and competes against SPN, SLB, and BHGE.

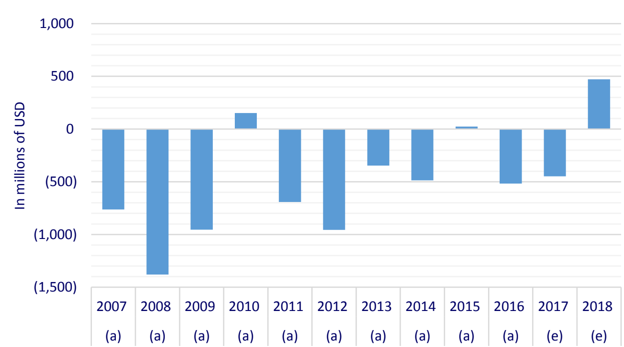
WFT has generated a $6 billion free cash flow loss over last ten years

WFT's free cash flow generation has been very inconsistent throughout its history. During its period of acquisitions, the focus was on adding product lines, expanding its geographic footprint, and growing market share. Sometimes this focus would lead to taking on contracts that were greater than WFT's scope/ capabilities, such as Zubair in Iraq. When the company was undergoing its strategic review and separating out its core and non-core product lines, it was clear that its core product lines were contributing much of the profitability and cash flow in the company. Pressure pumping has been a drag on profitability for a while and with the separation it should help improve North American margins.

Its Latin American footprint has grown and with it WFT's receivables have been impacted by this growth as LatAm accounted for nearly 40% of its outstanding A/R balances at the end of 2016. WFT has also raised cash from recent debt and equity offerings (which we discuss in more detail in the next section), from non-core divestitures (the rest of the rig business is still up for sale), and from its recent OneStim JV which gave WFT a one-time $535mm cash payment.

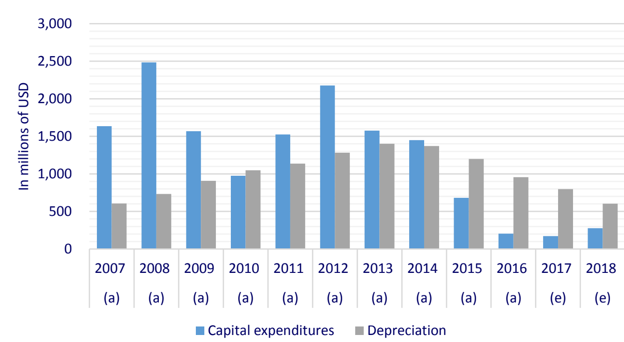
Uses of cash have been on working capital, R&D, capex, acquisitions, interest payments and debt repayment. McCollum has recognized that there is a lot of cash tied up in working capital for WFT and plans to focus the company to bring down inventory levels to a more appropriate level. Recent savings generated from lowering corporate expenses will be reinvested into new technologies and process improvements in order to improve the overall efficiency of the company.

Figure 634: Free cash flow



Source: Company reports, Deutsche Bank

Figure 635: Capital expenditures



Source: Company reports, Deutsche Bank

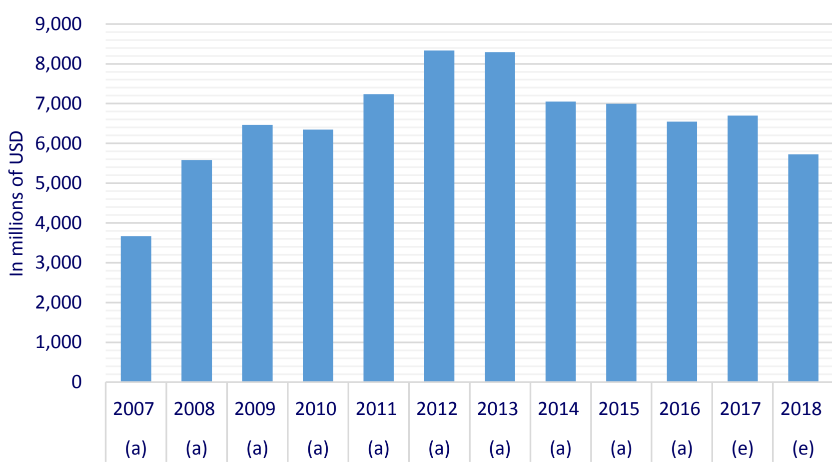
Capex levels have been trending lower as well the past few years as it finished building out its international expansion. WFT will likely have to put some capex into its land rig fleet as it positions it for divestiture. Also in preparation for the OneStim JV, WFT purchased certain leased equipment in its NAM pressure pumping business for $240mm in January 2017.

Balance sheet and liquidity

During 2016, WFT through a series of debt offerings and a secured term loan raised net proceeds of $3.7bn. The proceeds from those offerings were used to buyback senior notes ($1.9bn), repay some of its revolver, and for general corporate purposes. Also in 2016, WFT issued 200mm shares of equity for a total cash proceeds of $1.1bn. The company also issued one warrant in November 2016 that allows the holder to purchase 84.5mm shares on or prior to May 21, 2019 at an exercise price of $6.43. Net interest expense was $499mm in FY16 compared to $468mm in 2015 as higher interest on the newly issued debt was only partially offset by the debt repurchases.

WFT spent much of last year working to extend its liquidity runway due to its debt and equity issuances last year. The largest piece of its debt maturity wall now stands in 2021, but the near term levels are much more manageable. McCollum has made it clear that debt repayment will be a key part of the strategy as profitability and cash flow generation improves.

Figure 636: Net debt



Source: Deutsche Bank

Figure 637: Income Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Segment revenues:											
North America	2,762	4,167	6,025	6,824	6,390	6,852	3,494	1,878	1,997	2,077	2,149
Latin America	2,079	1,619	2,226	3,077	2,836	2,282	1,746	1,059	984	1,051	1,109
Eur/ SSA/ Russia	1,619	1,984	2,296	2,519	2,693	2,129	1,533	939	991	1,041	1,083
M East/ N Afr/ Asia	2,372	2,451	2,441	2,795	3,344	2,406	1,947	1,453	1,400	1,622	1,756
Land Drilling	0	0	0	0	0	1,242	713	420	392	414	431
Total revenue	8,833	10,221	12,988	15,215	15,263	14,911	9,433	5,749	5,764	6,205	6,529
Segment EBIT:											
North America	191	693	1,258	1,129	822	1,037	(224)	(382)	23	197	226
Latin America	277	51	254	403	365	379	315	65	33	84	132
Eur/ SSA/ Russia	223	240	282	335	298	399	217	(11)	11	106	174
M East/ N Afr/ Asia	445	263	23	78	230	267	211	7	41	174	260
Land Drilling	0	0	0	0	0	(11)	13	(87)	(84)	20	77
G&A	(174)	(173)	(198)	(196)	(200)	(178)	(194)	(139)	(135)	(135)	(146)
R&D	(196)	(216)	(245)	(257)	(266)	(290)	(231)	(159)	(147)	(144)	(144)
EBIT	766	859	1,374	1,492	1,249	1,603	107	(706)	(258)	303	578
Interest (expense)	(367)	(406)	(453)	(486)	(516)	(498)	(468)	(499)	(567)	(539)	(491)
Interest income	0	0	0	0	0	0	0	0	0	0	0
Equity income	0	0	0	0	0	0	0	0	0	0	0
Other income	(44)	(53)	(101)	(100)	(77)	(17)	3	(24)	(41)	(40)	(40)
PBT	355	401	820	906	656	1,088	(358)	(1,229)	(866)	(277)	48
Income tax (expense)	(163)	(241)	(489)	(472)	(162)	(258)	138	104	(111)	28	(7)
Non-controlling interest	(26)	(15)	(16)	(28)	(31)	(45)	(34)	(19)	(23)	(24)	(24)
Preferred dividends	0	0	0	0	0	0	0	0	0	0	0
Net income (operating)	166	145	315	406	463	785	(254)	(1,144)	(1,001)	(273)	17
Discontinued ops	0	0	0	0	0	0	0	0	0	0	0
Unusual after-tax	(77)	(362)	(134)	(990)	(806)	(1,369)	(1,731)	(2,248)	(54)	0	0
Net income (GAAP)	**89**	**(217)**	**181**	**(584)**	**(343)**	**(584)**	**(1,985)**	**(3,392)**	**(1,055)**	**(273)**	**17**
Operating EPS	**0.23**	**0.19**	**0.42**	**0.53**	**0.60**	**1.01**	**(0.33)**	**(1.29)**	**(1.01)**	**(0.28)**	**0.02**
GAAP EPS	0.12	(0.29)	0.24	(0.76)	(0.44)	(0.75)	(2.55)	(3.82)	(1.07)	(0.28)	0.02
Diluted shares	723	743	758	768	774	779	779	887	990	990	990
EBITDA	**1,672**	**1,907**	**2,512**	**2,774**	**2,651**	**2,974**	**1,307**	**250**	**540**	**905**	**1,040**
EBITDA margin	18.9%	18.7%	19.3%	18.2%	17.4%	19.9%	13.9%	4.3%	9.4%	14.6%	15.9%
EBIT margin	8.7%	8.4%	10.6%	9.8%	8.2%	10.8%	1.1%	-12.3%	-4.5%	4.9%	8.9%
Tax rate	45.9%	60.2%	59.6%	52.1%	24.7%	23.7%	38.5%	8.5%	-12.9%	10.0%	15.0%
Segment EBIT margins	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
North America	6.9%	16.6%	20.9%	16.5%	12.9%	15.1%	-6.4%	-20.3%	1.2%	9.5%	10.5%
Latin America	13.3%	3.1%	11.4%	13.1%	12.9%	16.6%	18.0%	6.1%	3.3%	8.0%	11.9%
Eur/ SSA/ Russia	13.8%	12.1%	12.3%	13.3%	11.1%	18.7%	14.2%	-1.2%	1.2%	10.2%	16.0%
M East/ N Afr/ Asia	18.7%	10.7%	0.9%	2.8%	6.9%	11.1%	10.8%	0.5%	2.9%	10.7%	14.8%
Land Drilling						-0.9%	1.8%	-20.7%	-21.4%	4.9%	17.9%
Segment margin	12.9%	12.2%	14.0%	12.8%	11.2%	13.9%	5.6%	-7.1%	0.4%	9.4%	13.3%

Source: Deutsche Bank

Figure 638: Cash Flow Statement

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Net income	166	145	315	406	463	785	(254)	(1,144)	(1,001)	(273)	17
Depreciation	907	1,048	1,138	1,282	1,402	1,371	1,200	956	798	603	462
Deferred tax	(100)	55	149	(13)	(33)	(66)	(448)	381	4	0	0
Chg in receivables	100	(190)	(626)	(705)	(12)	78	1,031	214	(54)	13	11
Chg in inventories	(46)	(360)	(606)	(738)	129	(167)	349	260	6	430	298
Chg in payables	41	298	237	543	69	(150)	(813)	(21)	25	(17)	39
Other	(454)	132	226	446	(789)	(888)	(359)	(960)	(55)	(5)	(6)
Cash from operations	614	1,128	833	1,221	1,229	963	706	(314)	(277)	750	819
Capital expenditures	(1,569)	(977)	(1,524)	(2,177)	(1,575)	(1,450)	(682)	(204)	(171)	(279)	(358)
Free cash flow	(955)	151	(691)	(956)	(346)	(487)	24	(518)	(448)	471	461
Acquisitions	(44)	(170)	(166)	(190)	(17)	10	(22)	(15)	(243)	0	0
Asset sales	123	197	31	61	488	1,770	45	49	560	500	0
Dividends paid	0	0	0	0	0	0	0	0	0	0	0
ESPP | options	6	0	0	65	0	22	0	0	0	0	0
Equity issuance, net	0	0	0	0	0	0	0	1,071	0	0	0
Debt issuance, net	834	(29)	798	990	12	(1,183)	31	206	94	(116)	(539)
Other	50	14	(17)	(41)	(2)	(93)	(85)	(223)	(31)	0	0
Chg in cash	14	163	(45)	(71)	135	39	(7)	570	(68)	855	(78)
FCF per share	(1.32)	0.20	(0.91)	(1.25)	(0.45)	(0.63)	0.03	(0.58)	(0.45)	0.48	0.47
Capex / revenue	0.18	0.10	0.12	0.14	0.10	0.10	0.07	0.04	0.03	0.04	0.05
Capex / depreciation	1.73	0.93	1.34	1.70	1.12	1.06	0.57	0.21	0.21	0.46	0.78

Source: Deutsche Bank

Figure 639: Balance Sheet

	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(e)	(e)	(e)
In millions of USD	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Cash and equivalents	253	416	371	300	435	474	467	1,037	969	1,824	1,746
Accounts receivable	2,511	2,629	3,233	3,885	3,594	3,015	1,781	1,383	1,207	1,194	1,183
Inventories	2,238	2,590	3,158	3,675	3,371	3,087	2,344	1,802	1,675	1,246	948
Other current assets	1,043	860	969	1,169	1,374	1,368	972	688	1,690	1,767	1,859
Total current assets	6,045	6,495	7,731	9,029	8,774	7,944	5,564	4,910	5,541	6,031	5,736
Net PP&E	6,995	6,945	7,287	8,299	8,368	7,123	5,679	4,480	3,279	2,455	2,351
Goodwill	4,243	4,279	4,423	3,871	3,709	3,011	2,803	2,797	2,293	2,293	2,293
Equity in affiliates	533	540	616	646	296	106	76	66	63	63	63
Other assets	966	940	994	950	830	705	665	411	579	606	637
Total assets	18,782	19,199	21,051	22,795	21,977	18,889	14,787	12,664	11,755	11,448	11,080
Accounts payable	1,002	1,335	1,571	2,108	2,091	1,736	948	845	878	861	899
Current debt	870	235	1,320	1,585	1,666	727	1,582	179	152	543	379
Other current liabilities	1,184	1,131	1,392	2,017	1,942	1,564	1,501	1,404	1,497	1,566	1,647
Total current liabilities	3,056	2,701	4,283	5,710	5,699	4,027	4,031	2,428	2,527	2,969	2,925
Long-term debt	5,847	6,530	6,286	7,049	7,061	6,798	5,879	7,403	7,513	7,007	6,631
Deferred taxes	0	0	0	0	0	0	0	0	0	0	0
Other LT liabilities	704	850	1,137	1,218	1,014	1,031	512	765	656	687	722
Non-controlling int	79	67	21	32	41	75	61	56	69	93	117
Shareholders' equity	9,095	9,051	9,324	8,786	8,162	6,958	4,304	2,012	989	692	685
Total liabilities and equity	18,782	19,199	21,051	22,795	21,977	18,889	14,787	12,664	11,755	11,448	11,080
Total debt	6,717	6,765	7,606	8,634	8,727	7,525	7,461	7,582	7,665	7,549	7,010
Net debt	6,464	6,349	7,235	8,334	8,292	7,051	6,994	6,545	6,696	5,725	5,264
Debt/capital	42%	43%	45%	50%	52%	52%	63%	79%	89%	92%	91%
Debt/equity	74%	75%	82%	98%	107%	108%	173%	377%	775%	1091%	1024%
Debt turns	**4.0**	**3.5**	**3.0**	**3.1**	**3.3**	**2.5**	**5.7**	**30.3**	**14.2**	**8.3**	**6.7**

Source: Deutsche Bank

Appendix 1

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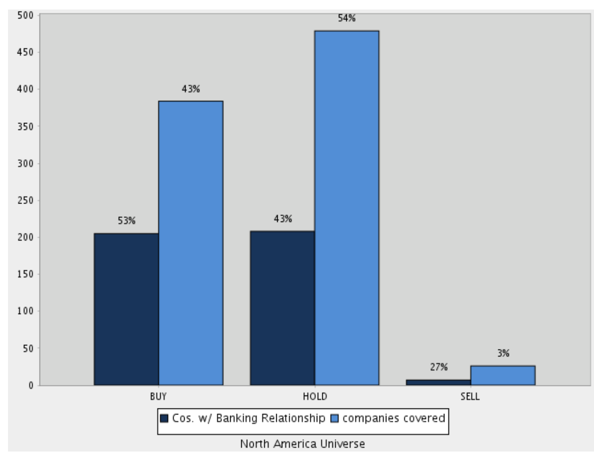

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