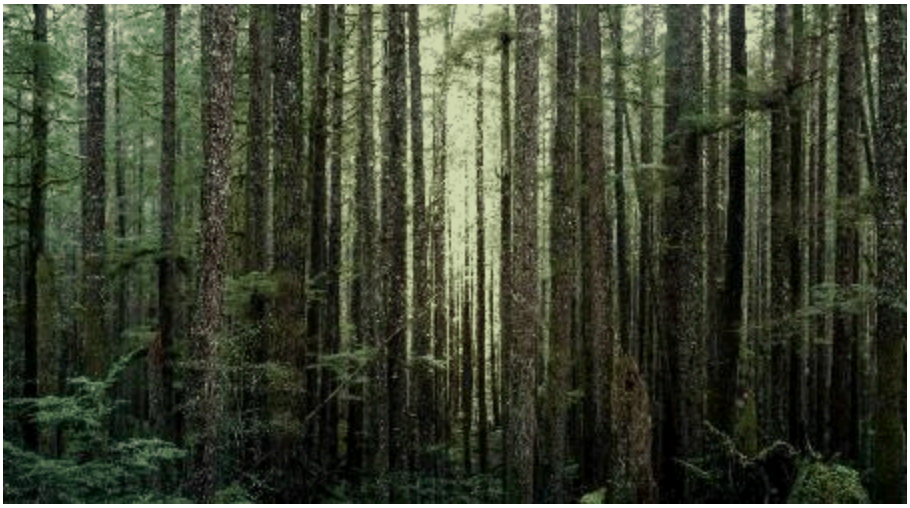
J.P.Morgan

2021 Oil Services & Equipment Outlook

"Hunger Games": Lacking Sustenance in Upstream, OFS May Need to Seek New Hunting Grounds



Oil Services and Equipment

Sean C Meakim, CFA [AC]
(1-212) 622-6684
sean.meakim@jpmorgan.com
Bloomberg JPMA MEAKIM <GO>

Andrew P Herring, CFA
(1-212) 622-8585
andrew.p.herring@jpmorgan.com

Terrell Rose
(1-212) 622-1010
terrell.rose@jpmchase.com

Samantha M Trent
(1-212) 622-5096
samantha.m.trent@jpmchase.com

J.P. Morgan Securities LLC

You've got to go through it to get to the end of it. Oil fundamentals have been starving the Oil Services sector for more than half a decade, with little relief in sight. The sector is poised to trail the broader market for the fourth consecutive year by ~40% on average and now in nine of the past ten, with the lone exception a late year fluke in 2016 as the first OPEC+ cut was consummated. **With ~90% of the sector's market cap erased, it appears our long-held bearish call on the stocks has largely run its course. Yet that's insufficient to justify a bullish case for the group, not with headwinds to E&P spending coming from all angles** (investor-driven austerity, tech-led secular deflation, ESG demands, renewables). As we laid out a year ago, we expect the market to sort the stocks between cash flow "wheat and chaff". The pandemic appears to have forced hard decisions regarding cost-out, divesting of non-core assets and prioritizing cash. In spite of this progress, we believe group earnings will be lower cycle/cycle, and the road to "normalized" metrics appears to be a long one. While the reopening trade likely helps the group early in 2021, we suspect further gains will be tough to hold by 2H21 without positive revisions to 2022 estimates, and see the stocks as range-bound (albeit with high amplitude courtesy of "the law of small numbers").

It takes ten times as long to put yourself back together than it does to fall apart. Despite the dismal YTD performance (OSX -41% v. S&P +15%), the sector is on a tear of late (+75% off the 10/28 bottom) on the back of economic reopening tied to positive vaccine news. Equity investors are using OFS stocks for their oil beta as Brent marches towards its long-term gravitational center of ~$60. While the economic cadence to support that mean reversion will continue to be debated, we emphasize that this group's "earnings beta" to oil remains asymmetric: all of the downside, but muted upside given all the structural headwinds. **With both Brent and WTI near $50, a call on the upstream still +12-18 months away, and an elongated OPEC+ tightrope walk in between, we think the group has delivered most of the beta it can offer.** Looking ahead, we recommend a barbell of defensive and (select) offensive exposures, with backlog/durable earnings paired with early cycle completions leverage and cheap valuations, all backed by strong balance sheets. We see parallels to the enthusiasm of late 2016, which led to disappointment in 2017 as the sector's earnings progression underwhelmed. **Top OWs: BKR, FTI, NESR, NEX; top UWs: RIG, OII, NBR.**

We are hosting a conference call on Friday, December 18th at 10am ET on our 2021 Outlook:

Conference Call:
JPM 2021 Oil Services and Equipment Outlook

Hosted by:
Sean Meakim, CFA
Oil Services Equity Analyst

Date: December 18th, 2020

Time: 10:00am ET

DIAL-IN INFO: Please contact your JPM sales contact for details*

See page 197 for analyst certification and important disclosures.

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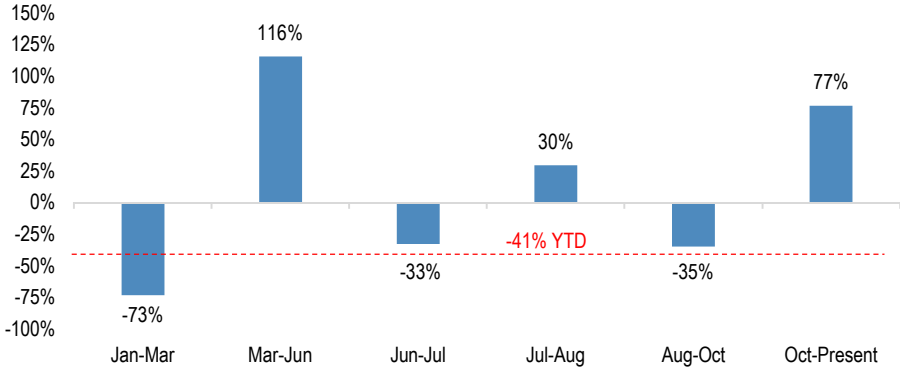
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

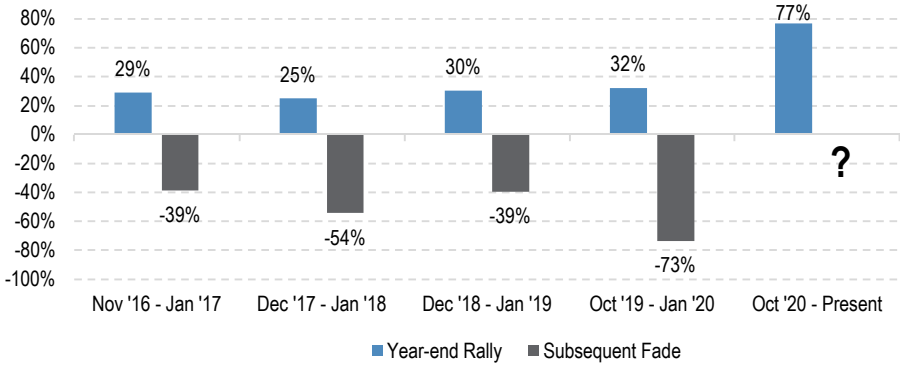
- **A little hope is effective, a lot of hope is dangerous.** In last year's outlook we quoted Jim Collins' book *Good to Great*, in which former Vice Admiral of the U.S. Navy and Vietnam prisoner of war James Stockdale offered this paradoxical advice: "You must never confuse faith that you will prevail in the end – which you can never afford to lose – with the discipline to confront the most brutal facts of your current reality, whatever they might be." The facts on the ground became decidedly more brutal for OFS only months later as the pandemic led to an unprecedented activity declines, but the sector accelerated cost reductions plans often already underway and did an admirable job of preserving margin and cash considering the circumstances. **While the industry is confronting its current reality, investors are naturally looking forward to next cycle's normalized EBITDA and FCF and getting more optimistic of late**. We've committed considerable efforts to this endeavor in 2020 (see A View to 2025 and our Fall OFS Playbook for more detail), and after running sensitivities from the bear case to the bull, we conclude that although normalized earnings power is meaningfully higher than what the industry is experiencing in 2020-2021, the market is already paying up for more than that. Beyond the pandemic disruptions to oil demand, we believe productivity and efficiency gains will lead to lower activity cycle/cycle. Further, we think short cycle producers (shale plus Middle East OPEC) will continue to deliver most of the incremental barrels. Last, with shale's forced austerity and pledges to spend well below cash flow, we think $60 is the new $50 in WTI as the inducement price for growth is higher (not gone). **We are concerned the market may be inclined to overestimate the translation of higher oil prices near term into service activity.**

Figure 1: OSX Performance from Peak to Trough in 2020



Source: Bloomberg Finance L.P.

Figure 2: Historical OSX Year-end Rallies and Subsequent Fades

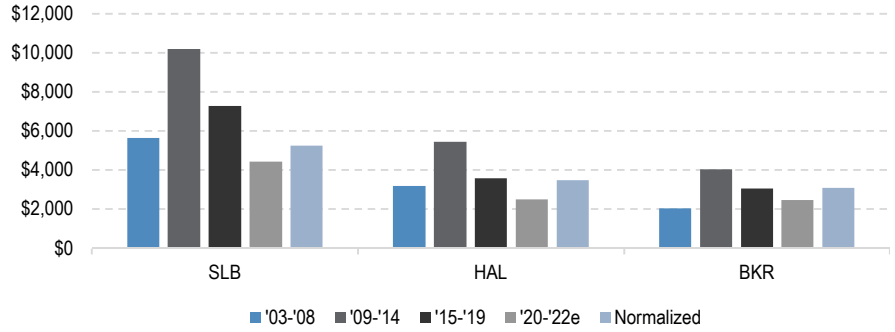


Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

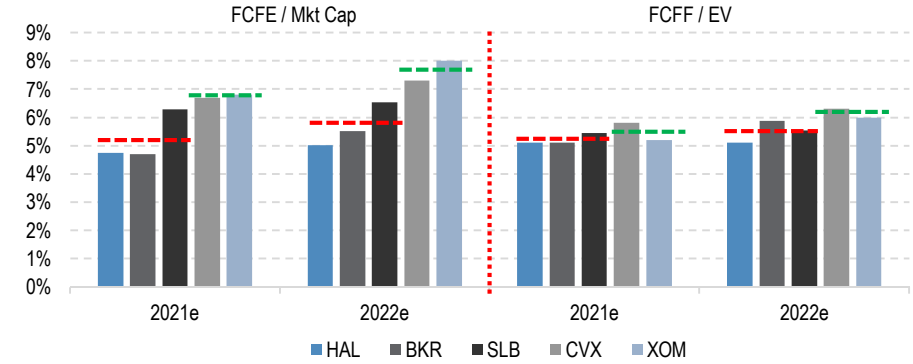
- **As long as you can find yourself, you'll never starve.** Oilfield services is no longer a growth sector (we've long made this case pre-2020), and **our normalized framework** emphasizes sensitivities of what each company's activity can look like this upcoming cycle. In most cases we expect earnings to be down cycle/cycle (as was the case from '15-'19), driven by dwindling top line opportunities (underpinned by efficiencies and deflation) which is only partially offset by the strong cost-out efforts implemented in 2020. With lower earnings comes lower FCF, even with more capital discipline, and we argue that **OFS needs to be more competitive than other cyclicals on a FCF/EV yield basis to garner generalist interest** and thus must focus on further rationalizing. As the market prices in what looks like our more "bearish" activity scenarios (offering a HSD/LDD yield), we are inclined to add to positions, but when more bullish sentiment appears (as is increasingly the case now), resulting in MSD yields, valuations look pretty full, and we prefer to fade the stocks, waiting for a more attractive risk/reward profile to (eventually) reappear. **Within the diversifieds, we continue to rank them 1) BKR (OW), 2) HAL (N) and 3) SLB (N).** As we detail in this report, we've been recommending the NAM completions trade since our Fall Playbook, and think there's a little more juice to squeeze out of it through 4Q and maybe 1Q results next year (benefitting HAL). Yet we think as 2021 bears out, BKR's more defensive characteristics of backlog and balance sheet for the same FCF/EV yield screens most attractive.

Figure 3: Big Three EBITDA by Cycle ($mm)



Source: Company reports, J.P. Morgan estimates. Note: does not make adjustments for acquisitions/divestitures (e.g. SLB-CAM).

Figure 4: Big Three FCF Yields (FCFE and FCFF) v. the Majors CVX, XOM

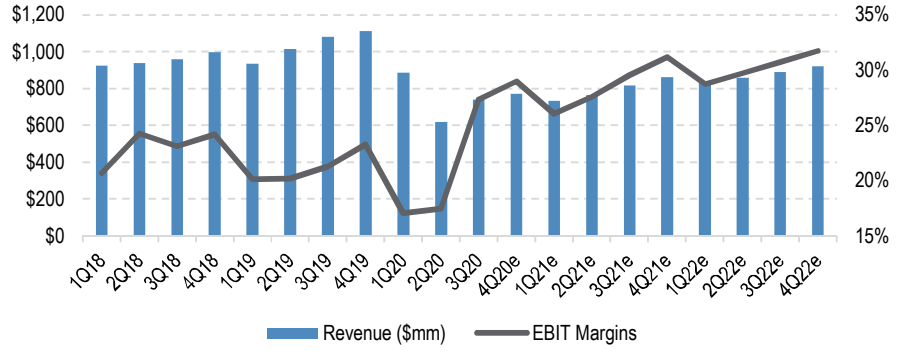


Source: Company reports, J.P. Morgan estimates, Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

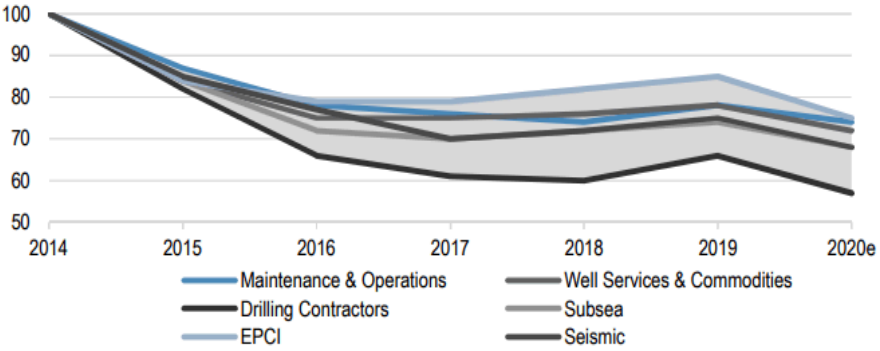
- **It's the things we love most that destroy us.** In 2020, **the pandemic helped to accelerate digital adoption** (or at the very least conversations) across our coverage; with travel restricted globally, remote operations were unsurprisingly sought after. The **digitalization of the oilfield is one of the biggest levers of our secular deflation thesis** (cost/boe) and encompasses a wide array of efficiency drivers (e.g., AI/ML, automation, multiskilling, software enabling hardware, preventative R&M, additive manufacturing) and has been in the works long before 2020. Investors were given a taste of the potential digital has to offer with **SLB's** new financials recently disclosing its Digital & Integration division boasting considerably higher margins v. core OFS (see below). Ultimately we view the setup as digital "versus" OFS, meaning we expect these offerings to become the "cost of admission" to win hardware utilization. **While digital appears plainly to be value accretive, whether that value is captured by its creators or transferred to their E&P customers likely remains a key debate in 2021 and beyond.**

Figure 5: SLB Digital & Integration Revenue v. EBIT Margins



Source: Company filings, J.P. Morgan estimates.

Figure 6: OFS Service Cost Deflation (2014=100)

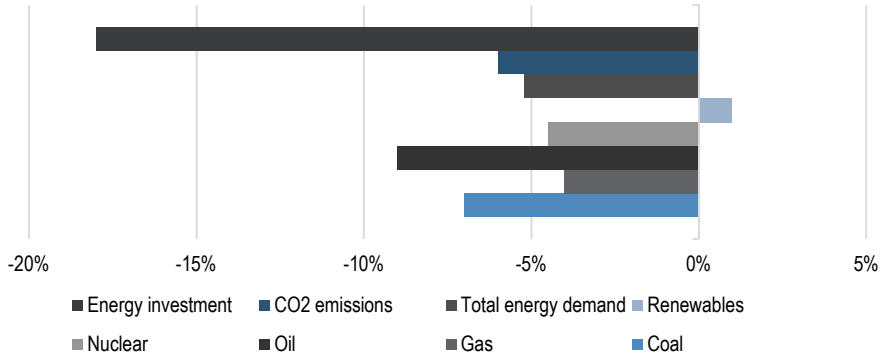


Source: Rystad, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

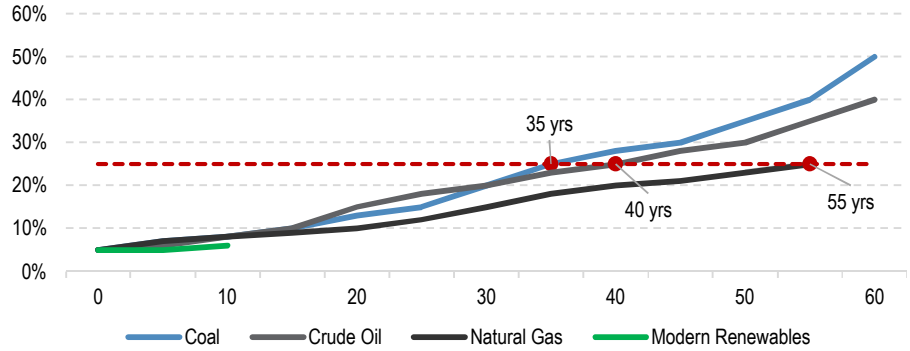
- **Fire is catching, and if we burn, you burn with us!** As the upstream increasingly shies away from growth and capital flows toward alternative energy sources accelerate, **we believe OFS is left with little choice but to seek New Energy channels** to generate revenue. De-carbonization is not an end in itself either, as energy producers (including the IOCs) seek to boost returns by expanding their portfolios of renewables. **Plenty of opportunities exist in the overlap between "old" and "new" energy** for services and equipment providers (especially offshore) to apply their traditional expertise in tangential areas tied to renewables. Hydrogen, offshore wind, geothermal, and CCS are channels in which we see the most significant opportunities for our coverage, though we still have reservations about their ability to scale in a way that allows for material addressable markets to evolve for our coverage to pursue. Notably, a select few are already securing their spots as enablers of the transition (e.g., **BKR**, **FTI**), and others expanding capabilities (e.g., **SLB**, **NOV**). **However, the trade-off is not a pleasant one, as the capital spend lost in upstream does not look to be fully replaced in these renewable channels**, let alone considering OFS's mostly nascent market share.

Figure 7: 2020 Estimated Y/Y Change in Energy Demand and CO_2 Emissions



Source: IEA.

Figure 8: Total Years for Energy Sources to Supply ~25% of Global Demand

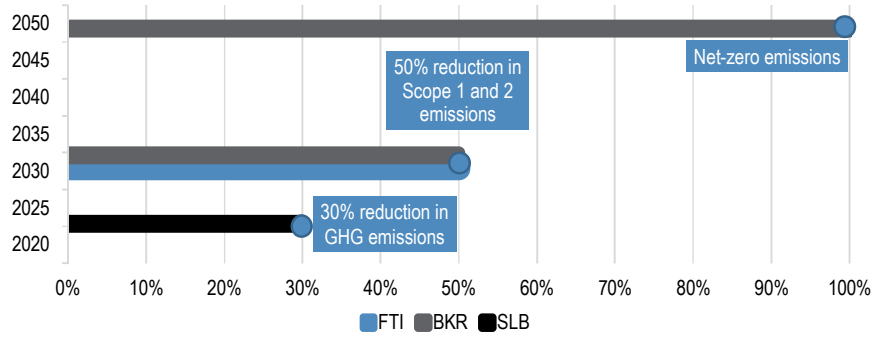


Source: V. Smil, BP, JPMAM.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

- **It's both a time for repentance and a time for thanks.** The importance of environmental, social and governmental (**ESG**) issues **has increased dramatically among investors**, and 2020's pandemic and shift in public sentiment seem to have only raised the awareness among those leading the oil services sector. The topic is not new in OFS but we have witnessed enhanced reporting through sustainability reports and greater detailing on efforts in investor presentations. **The "E" unsurprisingly remains in the spotlight, as more responsibility has been placed on OFS as de-carbonization efforts pick up across the energy value chain** with some companies even committing to specific emission reduction goals (e.g. **BKR**, **SLB**, **FTI**, **HAL**). After examining initiatives across our coverage which serve to help both OFS and producers de-carbonize (e.g. e-frac, dual-fuel engines), we think it will be important for the priorities on both sides to be aligned in order to achieve climate goals.

Figure 9: FTI, BKR, and SLB Emissions Reductions Goals

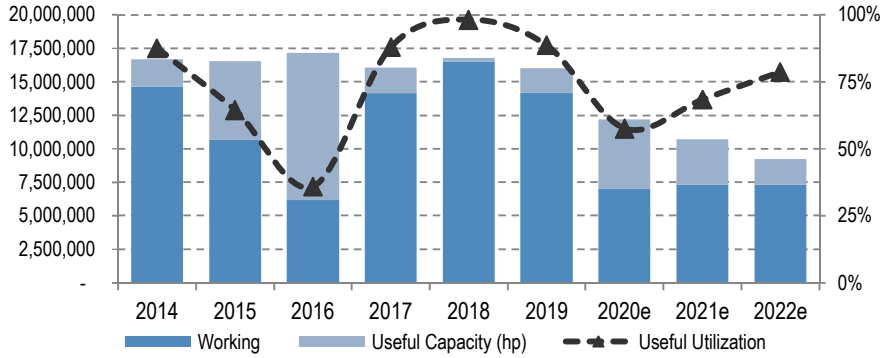


Source: Company reports.

- **No one can help but admire your spirit.** Into 2021, **we continue to favor NAM exposures over int'l/offshore and specifically prefer completions over drilling.** We see momentum building in NAM D&C activity into 2021 and expect demand for land rigs and fleets to expand next year. We forecast the L-48 rig count climbing to the high-300s by 2H21 and for frac fleets to peak around ~180 during the year. However after ~40% of frac nameplate capacity was purged from the market, we believe supply and demand will tighten for frac well before drilling, which has ample super-spec rig capacity. As such, even after the good period of performance recently (NAM +82% since 11/6, OSX +62%), we think there is further room to run for select U.S. onshore-focused stocks within our coverage that look relatively cheap on a "normalized" basis. This makes **North America the one area in our coverage where we recommend an "offense" strategy**, to complement our general recommendation of "defense" centered on backlog-driven stocks. In particular, for 1H21 we favor pressure pumpers with solid balance sheets, strong operational track records, and relatively cheap valuations. We view the drillers as relatively disadvantaged to completions with less rate of change potential in 2021. As we move through 2021, a stalling of activity on flat production might lead to some volatility in the stocks, but that can be addressed closer to midyear **As a result we recommend NEX and PUMP among the pumpers, as well as WHD, while we downgrade HP to N and maintain UW-ratings on NBR and PTEN.**

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 10: Frac Useful HP Utilization



Source: Spears, Rystad, J.P. Morgan estimates.

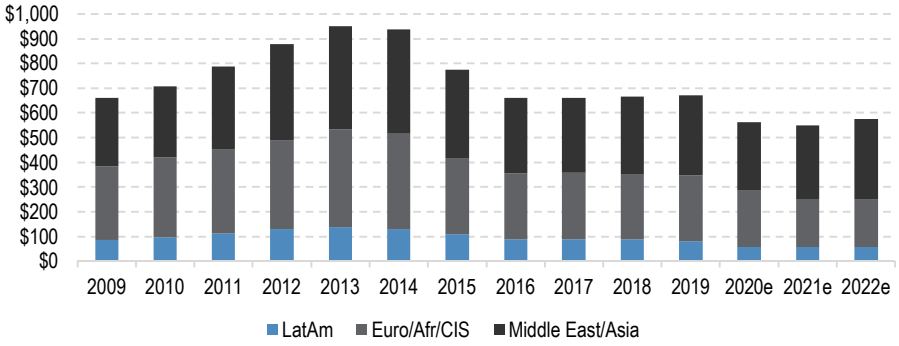
Figure 11: JPM Normalized Scenarios for the Coming Upstream Cycle

	Prior Cycles		Normalized Cases				
NAM	**'09-'14**	**'15-'19**	**Bear**	**"Low" Base**	**Normalized**	**"High" Base**	**Bull**
Average WTI Price	$87	$53	Low-$40s	Low-$50s	Mid-$50s	Low-$60s	$70+
Annual Oil Production Growth (mmbbl/d)	+750	+1,038	Flat	+500	+600	+1,000	+1,500
Average U.S. Land Rig Count	1,712	870	400	550	635	750	1,000
Average U.S. Oil Rig Count	961	697	330	480	550	660	900
Average U.S. Gas Rig Count	751	172	70	80	85	90	100
Average U.S. Frac Spread Count		346	163	225	250	300	425
International							
Average Brent Price	$96	$58	High-$40s	High-$50s	Low-$60s	High-$60s	$80+
Average Int'l Rig Count	1,186	1,033	800	850	880	950	1,050
Average Int'l Land Rig Count	881	802	650	675	690	725	800
Average Int'l Offshore Rig Count	305	230	150	175	190	225	250

Source: Baker Hughes, Genscape, J.P. Morgan E&P Research, J.P. Morgan OFS estimates.

- **Whatever you do, don't let them starve.** In the face of intense capital austerity and now competing calls on capital (e.g., balance sheet repair, shareholder returns and new energy), **we remain conservative on the international E&P capex cycle** and next year's activity recovery alongside the vagaries of oil demand lingering. We think Brent north of $60 (sustained) is needed to justify meaningful reactivations, and even then we suspect a tentative push by the IOCs. We are skeptical of the diversifieds' expectation for a 2H21 ramp in activity to potentially save the year; on net we expect int'l spend to tick lower y/y even if there's sequential gains in 2H21. **We still see reason for incremental optimism in 2022 into a more robust recovery beyond (2023-2025)**, though still not of the magnitude required to match last cycle's earnings power for most of our coverage.

Figure 12: E&P International Capex & Opex ($bn)

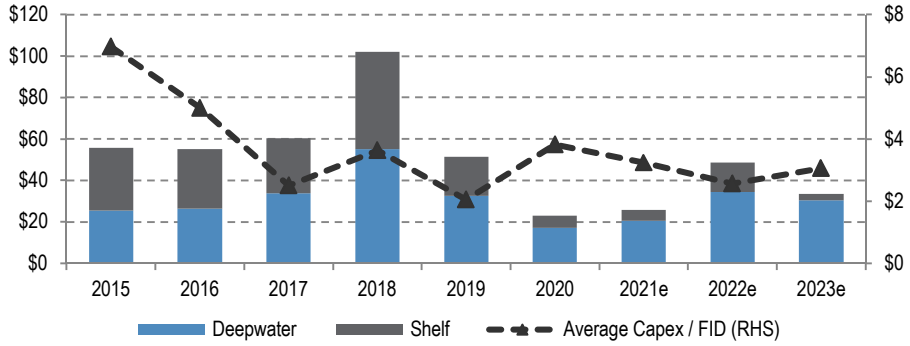


Source: Rystad, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

- **Some walks you have to take alone.** Across our coverage, **the offshore market arguably suffered the most from COVID-19** disruptions. Not only was the FID landscape relatively lackluster as promising projects slipped right, operations were on a stop-and-go basis, especially on rigs which are more or less cruise ships without the entertainment. The final blow to several over-levered offshore drillers therefore didn't arrive in the same manner we anticipated but still delivered the same result we had been calling for since our 2015 initiation. RIG is "the last man standing" for now as it navigates liability management, down -64% YTD (v. OSX -41%), but up 270% off the October low. **With the recent rally resulting in a meaty ~$1.5bn in market cap (v. $7bn in net debt), RIG is our top UW call.** Depending on potential M&A scenarios for the drillers currently in restructuring, enough cost rationalization could result in a more constructive market in 2023, but a lot has to happen between now and then. In 2021, RIG will have to determine if it's worth continuing to "go it alone" fighting for equity value or more prudent to join its peers in resetting its balance sheet. **By contrast, we continue to favor FTI** given its high-quality nature and attractive valuation in front of what seems like a forever impending spin. We envision an easier path for offshore equipment awards to return to normalized levels than drilling activity. On FTI we also think the separation of Technip Energies and the accompanying capital structure resolution will be a catalyst to unlock value on both sides, especially if the result taps into current sentiment for new energy exposure.

Figure 13: Total FID Capex ($bn) v. Average Capex ($bn)



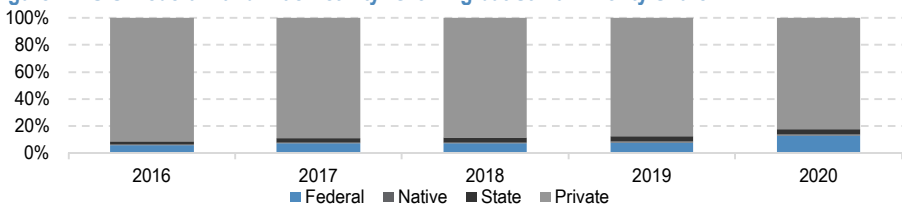
Source: Wood Mackenzie, J.P. Morgan estimates. Note: Assumes $50 Brent breakeven.

- **Throw me to the wolves and I'll return leading the pack.** We have suggested that **industry consolidation** would be a means to improve market economics and 2020 may be **an important step in the "more pain, more gain" cycle** we first described in 2015. Strong progress was made this year to right-size operations but more needs to be done as the upcoming cycle is likely to disappoint yet again. To compete for dwindling upstream business we think **small caps** would benefit from blocking up to gain relevance and scale top line while taking more cost out to improve margins and returns. In past cycles the **diversifieds** could be counted on as consolidators but the opposite has (rightfully) become the reality in recent years with non-core divestitures trading revenue for margin. The **pressure pumping** market has made progress on rationalizing capacity though we expect more to come out in 2021, resulting in a more constructive market into 2022. **Offshore rigs** have experienced a similar dynamic but as most of the industry emerges from restructuring more rigs need to be shed and that remains a "see it to believe it" story in our view. **We expect further consolidation efforts in 2021.**

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

- **I'm more than just a piece in their games.** Though president-elect Biden plans to implement more stringent oil & gas regulations than his predecessor, we see **risks of the most ambitious energy proposals from the Democrats passing as greatly curtailed now** after a "blue wave" Democratic sweep in Congress failed to materialize. The scope of possible regulations available to the incoming administration depends in large part on the results of the 1/5 Georgia Senate runoff elections, where a double-win by Democrats would lead to a 50/50 split Senate, with VP-elect Kamala Harris able to cast the tie-breaking vote. While we think a divided Congress is the most favorable outcome for OFS (and post-election stock reactions suggests this is a consensus view), even if the Democrats were to gain the slight Senate majority, we think it will be insufficient to pass the more onerous O&G restrictions under consideration. Regardless of the Senate outcome, investors should expect the Biden administration to implement new drilling and fracking restrictions on Federal lands (one way or another). Only ~10% of frac activity occurred on federal land in 2020, and we believe much of this work can be shifted to state/private lands if need be. Combined with E&Ps holding backlogs of permits and suggesting potential legal challenges to new regulations, **we see downsides of a federal drilling/frac ban as relatively limited for OFS through at least 2022.**

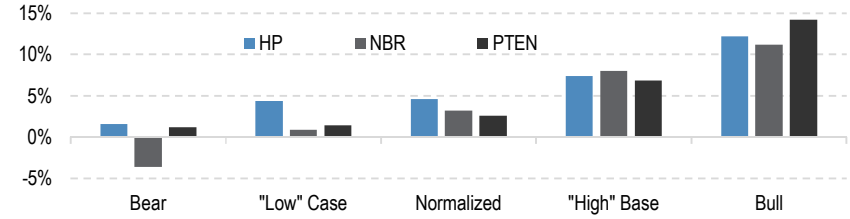
Figure 14: U.S. Federal Land Frac Activity: Growing but Still a Minority Share



Source: Rystad.

- **May the odds be ever in your favor.** We are downgrading the shares of H&P to Neutral (from Overweight) and Core Laboratories to Underweight (from Neutral) after their recent runs. Both companies remain leaders in our coverage with best-in-class franchises. The land drillers have been strong performers in the recent vaccine-fueled rally (+95% since 11/6 v. OSX +62%), **sending HP's stock to its highest level since the early June peak at ~$25/sh**, well ahead of our Dec-2021 price target of $21. We now model a normalized FCF/EV of ~5% for H&P, making the current valuation look fairly full to us, especially considering we think it will be years before the market will be conducive to HP generating those results. Though we acknowledge HP's high degree of "torque" to the recovering L-48 drilling market, with our relatively less favorable outlook for drillers compared to completions-levered stocks, **we see less upside optionality from here.** That said, we still keep H&P as our preferred stock among our land drilling coverage (both **NBR** and **PTEN** rated UW), and see relative strength derived from its solid balance sheet and industry-leading technology portfolio. We model FY2021/FY2022 EBITDA -41%/-28% lower than the Street, and maintain our Dec-2021 PT of $21.

Figure 15: FCF/EV Yield Estimates by Scenario, Sorted by "Normalized" Yield

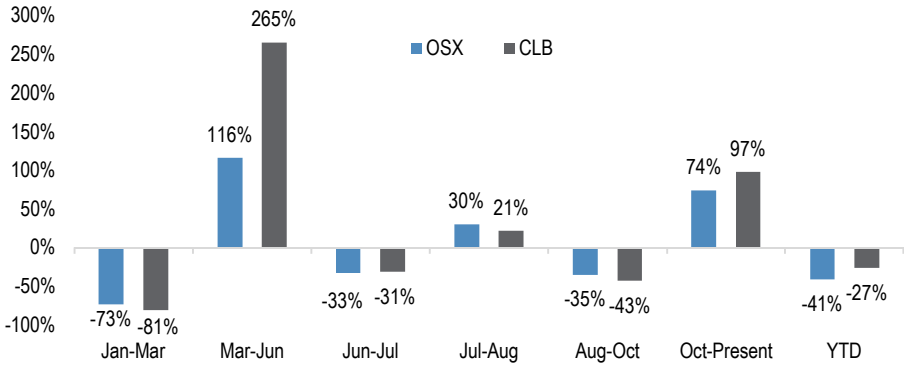


Source: Company reports, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

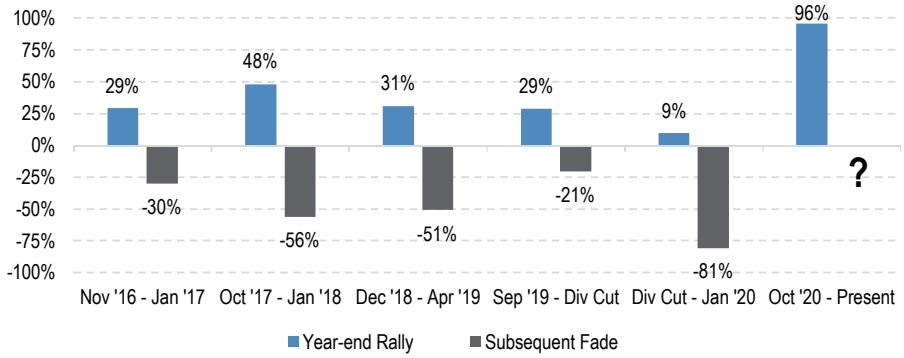
- **CLB shares have shown among the highest "oil beta" within our coverage of late** (+84% off the 10/28 low, +75% OSX), and as the sector has undergone one of its most robust yearend rallies in 2020, CLB shares have disproportionately benefitted. The business has very high operating leverage, which likely drives investor interest off a bottom in activity. However, we argue the fundamentals are unfortunately not so simple this cycle. While its Reservoir Description business remains one of the best franchises in all of OFS (alongside SLB's Characterization unit), it suffers the fate of being caught in the wrong cycle that favors short-cycle, well-identified resources. The Production Enhancement franchise has key attributes that are favorable but competition has increased significantly in the past few years in its core perf systems business, and we think pricing headwinds will be exacerbated by an overbuild in capacity that preceded the 2020 downtown. **We have confidence in this management team's ability to steer its balance sheet and generate cash, but we just don't think there will be enough FCF to justify the current valuation.** The company's election to issue $60mm of equity at-the-market this week underpins both of those assertions. At present, our estimates are only modestly below the Street in 2022, so our argument is more tied to buy-side expectations. This isn't the first time a late year rally has come to OFS, and most have ended with fades in the New Year (see below). **Our $18 Dec-2021 PT implies -30% downside from current levels.**

Figure 16: CLB Rallies and Fades in 2020 v. OSX



Source: Bloomberg Finance L.P.

Figure 17: Historical Year-end Rallies and Subsequent Fades for CLB



Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

- **Top Overweights: BKR, FTI, NESR, NEX.** We continue to favor **BKR** after it outperformed diversified peers this year (-14% v. SLB/HAL -43%/-18%) given its longer and later-cycle exposures in a recovery we expect to underwhelm, as well as its advantaged energy transition exposure, both supporting higher earnings cycle over cycle in our view. Relative valuation on FCF favors BKR in our view given its stronger balance sheet v. HAL/SLB. **FTI** remains a top pick given what we view as an advantaged position in its core subsea and LNG end markets with an attractive valuation in front of the Technip Energies spin. After admittedly lagging in 2020 in large part on uncertainty of the spin outcome, resolution in 2021 should help drive mean reversion. **NESR** has been the best performing stock in our coverage (+7% YTD v. OSX -41%) and we expect continued idiosyncratic growth with some upside to margins and a focus on strong capital allocation to support our "growth plus cash" thesis (potentially leading to an improved valuation v. NAM onshore comps). We believe **NEX** will be a key beneficiary of a tightening market for frac equipment in 2021, and given its strong operational track record, clean balance sheet, and valuation discount to peers we think NEX will outperform next year as its valuation gap closes on strong operational performance.

- **Top Underweights: RIG, NBR, OII. RIG** is indeed "the last man standing" among offshore driller equities (yet among our worst performers of those that didn't go into restructuring in 2020), showing management has navigated the offshore drilling downturn better than most (both operationally and financially), but with sizable market cap once again after the annual yearend beta rally in energy (despite a brutal offshore environment and its ongoing liability management exercises), we reload the shares as a top Underweight again in 2021. **NBR** has made strides in buying more time to address its sizable debt load, but with our more bearish outlook for land drilling margin progression and skepticism regarding through-cycle cash generation potential from the international business, we see NBR's equity as challenged, and recommend taking advantage of the recent rally. While **OII** will benefit from remaining cost-out and milestone payments in 2021, our still bearish outlook for offshore services leaves the view beyond that much more difficult. With a substantial debt load (Net Debt / JPMe 2021 EBITDA ~3x) and predilection to deploy growth capital, we expect the company's earnings recovery to lag much of our coverage and FCF to disappoint.

Table 1: JPM OFS Top Picks

Company	Ticker	Rating	PT	Up/ Down	JPM View
TechnipFMC	FTI	OW	$16	61%	Advantaged player in subsea and LNG end markets with solid new energy exposure featuring an attractive valuation and a defined value creating catalyst in the upcoming spin
NexTier Oilfield Solutions	NEX	OW	$5	36%	Combines strong balance sheet, solid management and good operational track record at a relative discount to peers; 2021 execution can drive mean reversion to peers
National Energy Services Reunited	NESR	OW	$11	12%	Offers idiosyncratic growth as a pure play in MENA with margins and capital discipline supporting our 'growth plus cash' thesis at only a NAM onshore valuation
Baker Hughes	BKR	OW	$23	4%	Long and late cycle exposures a relative benefit in underwhelming E&P capex recovery with advantaged industrial, LNG and new energy franchises and strong balance sheet
Nabors Industries	NBR	UW	$5	-93%	Heavy debt burden and challenged FCF prospects in both its U.S. and international operations leaves the equity disadvantaged in our view
Oceaneering	OII	UW	NR	N/A	With elevated debt in an unfavorable environment for offshore services we think OII is likely to lag its peers in recovery
Transocean	RIG	UW	NR	N/A	Despite proven operational performance we don't expect offshore drilling fundamentals to allow RIG to successfully fix its capital structure without entering restructuring like the rest of the market

Source: Bloomberg Finance L.P. and J.P. Morgan Estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

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Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

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Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 2: J.P. Morgan North America Oil Services, Equipment & Drilling Coverage Universe: Valuation

Company	Ticker	Rating	PT	Upside	Price	Div. Yield	Mkt Cap	EV	Turnover	Price / Earnings						EV/EBITDA						Price/Book		Free Cash Flow Yield					
			$/sh	%	$/sh	%	$,bn	$,bn	$,mm	2017	2018	2019	2020e	2021e	2022e	2017	2018	2019	2020e	2021e	2022e	Current	5-Yr Avg	2017	2018	2019	2020e	2021e	2022e
Baker Hughes	BKR	OW	$23	4%	$22.01	3.3%	22.3	26.0	154.5	N/A	33.8x	25.8x	N/A	38.9x	26.9x	10.5x	9.0x	8.6x	11.5x	10.8x	9.4x	1.9x	N/A	(4%)	3%	5%	1%	5%	5%
Halliburton	HAL	N	$14	(30%)	$20.07	0.9%	17.8	26.5	222.4	16.5x	10.6x	16.3x	33.0x	25.2x	19.1x	7.4x	6.1x	7.2x	11.2x	10.9x	10.0x	3.4x	3.4x	6%	6%	5%	6%	5%	5%
Schlumberger	SLB	N	$21	(9%)	$22.97	2.2%	31.9	46.3	283.8	15.3x	14.1x	15.5x	34.0x	28.4x	21.7x	6.8x	6.8x	7.0x	10.8x	10.6x	9.8x	2.7x	2.3x	5%	8%	8%	4%	6%	7%
Large Cap Service Avg				**(11%)**		**2.1%**	**24.0**	**32.9**		**15.9x**	**19.5x**	**19.2x**	**33.5x**	**30.8x**	**22.5x**	**8.2x**	**7.3x**	**7.6x**	**11.2x**	**10.8x**	**9.7x**	**2.7x**	**2.9x**	**3%**	**6%**	**6%**	**4%**	**5%**	**6%**
Cactus Inc.	WHD	OW	$28	(1%)	$28.15	1.3%	2.0	2.0	8.7	22.1x	17.2x	14.8x	38.7x	N/A	26.4x	18.0x	9.6x	8.8x	16.6x	19.0x	13.1x	5.8x	N/A	0%	5%	7%	6%	4%	4%
Dril-Quip	DRQ	OW	$36	9%	$32.91	-	1.1	0.8	6.9	N/A	N/A	N/A	N/A	N/A	N/A	13.4x	44.6x	14.2x	23.7x	19.7x	14.9x	1.1x	1.5x	6%	1%	0%	0%	6%	8%
TechnipFMC	FTI	OW	$16	61%	$9.96	1.3%	4.4	5.1	59.6	8.9x	12.5x	16.3x	28.2x	13.2x	13.1x	2.6x	3.3x	3.4x	4.6x	4.5x	4.5x	1.0x	1.3x	(5%)	(12%)	9%	3%	7%	8%
National Oilw ell Varco	NOV	N	$14	(1%)	$14.11	-	5.4	6.6	91.9	N/A	N/A	N/A	N/A	N/A	N/A	10.7x	7.2x	7.4x	16.5x	24.5x	15.2x	1.0x	0.9x	12%	5%	9%	13%	4%	3%
Oceaneering International	OII	UW			$8.65	-	0.9	1.5	9.2	N/A	N/A	N/A	N/A	N/A	N/A	6.7x	10.6x	9.3x	8.9x	9.6x	10.8x	1.6x	1.5x	5%	(9%)	1%	6%	13%	1%
Oil States International	OIS	N			$5.29	-	0.3	0.5	5.2	N/A	N/A	N/A	N/A	N/A	N/A	12.3x	3.5x	4.5x	22.7x	12.0x	7.7x	0.4x	1.1x	23%	6%	26%	39%	15%	7%
Tenaris	TS	N	$14	(16%)	$16.66	1.7%	9.8	9.4	26.0	18.0x	11.1x	13.1x	N/A	N/A	41.5x	9.8x	6.0x	6.7x	12.9x	11.7x	10.3x	0.9x	1.4x	(6%)	3%	12%	14%	4%	5%
Capital Equipment Avg				**11%**		**1.5%**	**3.4**	**3.7**		**16.4x**	**13.6x**	**14.7x**	**33.5x**	**13.2x**	**27.0x**	**10.5x**	**12.1x**	**7.8x**	**15.1x**	**14.4x**	**10.9x**	**1.7x**	**1.3x**	**5%**	**(0%)**	**9%**	**12%**	**8%**	**5%**
Core Laboratories	CLB	UW	$18	(37%)	$28.70	0.1%	1.1	1.5	12.2	14.3x	13.8x	16.4x	36.6x	35.4x	26.0x	11.4x	10.2x	11.7x	20.4x	19.7x	16.4x	17.0x	N/A	8%	7%	5%	6%	4%	4%
Liberty Oilfield Services	LBRT	N	$10	(11%)	$11.24	-	1.2	1.5	7.9	4.1x	5.1x	16.6x	N/A	N/A	32.5x	5.4x	3.5x	5.5x	38.4x	5.5x	4.1x	2.4x	N/A	(15%)	7%	6%	(2%)	(0%)	11%
National Energy Services Reunited	NESR	OW	$11	12%	$9.80	-	0.9	1.2	1.9	13.7x	11.1x	12.7x	15.8x	11.3x	7.7x	8.4x	7.4x	6.4x	5.5x	4.7x	3.8x	0.9x	N/A	(5%)	5%	4%	1%	(2%)	(2%)
NexTier Oilfield Solutions	NEX	OW	$5	36%	$3.69	-	0.8	0.8	5.7	12.5x	5.1x	N/A	N/A	N/A	N/A	2.5x	1.3x	1.8x	11.7x	6.9x	4.1x	1.2x	N/A	(36%)	13%	1%	(7%)	(4%)	12%
Nine Energy Services	NINE	N			$2.37	-	0.1	0.4	0.8	N/A	1.7x	N/A	N/A	N/A	N/A	6.2x	2.5x	3.1x	N/A	N/A	17.8x	1.6x	N/A	(68%)	73%	52%	10%	(24%)	(30%)
ProPetro Holding	PUMP	OW	$10	23%	$8.10	-	0.8	0.7	8.8	12.2x	2.9x	2.6x	N/A	N/A	19.5x	5.4x	1.9x	1.4x	5.4x	4.8x	3.9x	0.9x	N/A	(28%)	15%	5%	4%	2%	6%
Select Energy Services	WTTR	UW			$4.69	-	0.5	0.4	1.4	10.8x	4.7x	8.3x	N/A	N/A	N/A	3.1x	1.4x	2.0x	30.1x	16.7x	10.9x	0.8x	N/A	(30%)	13%	19%	21%	3%	3%
Small/Mid Cap Avg				**5%**		**0.1%**	**0.8**	**0.9**		**11.3x**	**6.3x**	**11.3x**	**26.2x**	**23.4x**	**21.4x**		**4.0x**	**4.6x**	**18.6x**	**9.7x**	**8.7x**	**3.5x**	**-**	**(25%)**	**19%**	**13%**	**5%**	**(3%)**	**1%**
NOW Inc.	DNOW	N			$6.67	-	0.7	0.5	6.6	N/A	18.4x	28.0x	N/A	N/A	N/A	N/A	4.1x	5.2x	N/A	N/A	20.3x	1.0x	1.2x	(17%)	9%	29%	19%	(3%)	2%
MRC Global	MRC	OW	$7	2%	$6.87	-	0.6	1.5	3.0	N/A	11.7x	15.7x	N/A	27.5x	13.6x	8.3x	5.3x	7.4x	16.5x	14.8x	11.7x	1.7x	1.9x	(12%)	(5%)	39%	40%	10%	15%
Energy Distribution Avg				**2%**		**-**	**0.7**	**1.0**		**-**	**15.0x**	**21.9x**	**-**	**27.5x**	**13.6x**	**8.3x**	**4.7x**	**6.3x**	**16.5x**	**14.8x**	**16.0x**	**1.3x**	**1.5x**	**(14%)**	**2%**	**34%**	**30%**	**3%**	**8%**
Helmerich & Payne	HP	N	$21	(16%)	$24.92	4.0%	2.7	2.7	43.7	N/A	N/A	16.3x	N/A	N/A	N/A	6.2x	4.0x	3.5x	17.2x	38.5x	14.5x	0.8x	1.2x	6%	4%	17%	11%	(0%)	1%
Nabors Industries	NBR	UW	$5	(93%)	$70.58	-	0.5	3.6	25.1	N/A	N/A	N/A	N/A	N/A	N/A	6.7x	4.8x	4.5x	6.5x	7.4x	5.8x	0.5x	0.7x	(129%)	(28%)	52%	38%	6%	27%
Patterson-UTI Energy	PTEN	UW			$5.72	1.4%	1.1	1.8	16.9	N/A	N/A	N/A	N/A	N/A	N/A	3.2x	2.2x	2.9x	8.1x	13.2x	9.8x	0.5x	1.1x	(18%)	7%	30%	16%	4%	7%
Onshore Drilling Avg				**(54%)**		**0.7%**	**1.4**	**2.7**		**-**	**-**	**16.3x**	**-**	**-**	**-**	**5.3x**	**3.6x**	**3.6x**	**10.6x**	**19.7x**	**10.0x**	**0.6x**	**1.0x**	**(47%)**	**(6%)**	**33%**	**22%**	**4%**	**12%**
Transocean	RIG	UW			$2.49	-	1.6	8.6	109.5	N/A	N/A	N/A	N/A	N/A	N/A	7.0x	8.0x	9.2x	9.3x	12.6x	12.8x	0.1x	0.3x	66%	32%	(3%)	(12%)	(83%)	(8%)
Offshore Drilling Avg				**-**		**-**	**1.6**	**8.6**		**-**	**-**	**-**	**-**	**-**	**-**	**7.0x**	**8.0x**	**9.2x**	**9.3x**	**12.6x**	**12.8x**	**0.1x**	**0.3x**	**66%**	**32%**	**(3%)**	**(12%)**	**(83%)**	**(8%)**
Coverage Group Avg				**(4%)**		**1.4%**	**4.7**	**6.5**		**13.5x**	**11.6x**	**15.6x**	**31.1x**	**25.7x**	**22.5x**	**7.8x**	**7.1x**	**6.2x**	**14.7x**	**13.2x**	**10.5x**	**2.1x**	**1.4x**	**(14%)**	**6%**	**16%**	**11%**	**3%**	**5%**

Source: J.P. Morgan estimates, Bloomberg Finance L.P.
Note: Prices as of December 15, 2020.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 3: J.P. Morgan North America Oil Services, Equipment & Drilling Coverage Universe: Estimate

Company	Ticker	Rating	PT	Upside	EPS						EBITDA						Cash from Operations						Capex						Free Cash Flow					
			$/sh	%	2017	2018	2019	2020e	2021e	2022e	2017	2018	2019	2020e	2021e	2022e	2017	2018	2019	2020e	2021e	2022e	2017	2018	2019	2020e	2021e	2022e	2017	2018	2019	2020e	2021e	2022e
Baker Hughes	BKR	OW	$23	4%	0.14	0.64	0.83	0.27	0.55	0.80	2,486	2,878	3,022	2,260	2,399	2,770	(84)	1,762	2,126	1,100	1,637	1,876	(849)	(995)	(976)	(772)	(552)	(603)	(933)	900	1,150	328	1,084	1,273
Halliburton	HAL	N	$14	(30%)	1.22	1.89	1.23	0.61	0.80	1.05	3,565	4,338	3,683	2,370	2,431	2,640	2,468	3,157	2,445	1,780	1,614	1,725	(1,373)	(2,026)	(1,530)	(751)	(759)	(816)	1,095	1,131	915	1,029	854	909
Schlumberger	SLB	N	$21	(9%)	1.50	1.62	1.48	0.67	0.80	1.05	6,824	6,807	6,610	4,255	4,361	4,712	5,663	5,713	5,431	2,827	3,242	3,505	(2,383)	(2,260)	(1,955)	(1,169)	(1,072)	(1,074)	1,671	2,472	2,695	1,230	2,011	2,090
Large Cap Service Avg				**(11%)**																														
Cactus Inc.	WHD	OW	$28	(1%)	1.24	1.60	1.86	0.71	0.54	1.04	112	211	229	122	107	155	35	167	210	150	115	125	(32)	(70)	(60)	(24)	(24)	(30)	3	97	150	126	92	95
Dril-Quip	DRQ	OW	$36	9%	0.35	(0.63)	0.09	0.10	0.20	0.50	57	17	54	32	39	51	108	46	15	17	80	98	(28)	(32)	(12)	(13)	(11)	(11)	80	13	3	4	68	87
TechnipFMC	FTI	OW	$16	61%	1.10	0.78	0.60	0.35	0.75	0.75	1,988	1,537	1,529	1,120	1,149	1,146	43	(185)	849	432	572	668	(256)	(368)	(454)	(307)	(256)	(291)	(213)	(554)	394	125	317	377
National Oilwell Varco	NOV	N	$14	(1%)	(0.41)	(0.06)	0.21	(0.10)	(0.35)	(0.05)	611	910	885	398	268	431	832	521	714	966	404	362	(192)	(244)	(233)	(240)	(200)	(172)	640	277	481	726	204	190
Oceaneering International	OII	UW			(0.08)	(0.71)	(0.89)	(0.50)	(0.43)	(0.56)	225	143	162	169	157	139	136	37	158	112	171	65	(94)	(110)	(148)	(57)	(57)	(54)	43	(73)	10	55	113	10
Oil States International	OIS	N			(1.07)	(0.14)	(0.60)	(1.11)	(0.84)	(0.57)	38	133	105	21	39	61	95	105	137	138	63	41	(35)	(88)	(56)	(15)	(17)	(19)	60	17	81	123	46	22
Tenaris	TS	N	$14	(16%)	0.91	1.48	1.26	0.20	0.25	0.40	943	1,536	1,382	716	785	890	(22)	611	1,528	1,567	547	626	(558)	(349)	(350)	(195)	(162)	(178)	(580)	261	1,178	1,372	385	448
Capital Equipment Avg				**11%**																														
Core Laboratories	CLB	UW	$18	(37%)	1.99	2.06	1.74	0.78	0.80	1.10	139	155	136	78	81	97	124	112	90	86	57	60	(19)	(22)	(22)	(11)	(10)	(9)	105	90	67	75	47	52
Liberty Oilfield Services	LBRT	N	$10	(11%)	2.62	2.13	0.65	(1.76)	(0.00)	0.33	281	438	277	39	277	370	194	351	261	69	220	353	(313)	(259)	(195)	(91)	(226)	(162)	(119)	92	66	(22)	(6)	191
National Energy Services Reunited	NESR	OW	$11	12%	0.70	0.87	0.76	0.61	0.85	1.25	142	162	186	215	256	314	-	-	93	139	170	221	-	-	(112)	(93)	(74)	(87)	-	-	(19)	45	96	134
NexTier Oilfield Solutions	NEX	OW	$5	36%	0.29	0.71	(0.13)	(1.22)	(0.90)	(0.45)	345	676	465	73	123	211	80	692	327	71	78	210	(352)	(589)	(321)	(125)	(110)	(119)	(272)	104	5	(55)	(32)	91
Nine Energy Services	NINE	N			(0.98)	1.54	(0.16)	(3.70)	(2.58)	(2.14)	56	141	113	(18)	(4)	19	6	90	101	16	(8)	(9)	(45)	(47)	(65)	(9)	(10)	(12)	(40)	43	36	7	(17)	(21)
ProPetro Holding	PUMP	OW	$10	23%	0.64	2.69	3.05	(0.03)	0.10	0.40	137	389	519	137	155	191	109	393	455	141	133	186	(286)	(284)	(503)	(112)	(119)	(133)	(177)	109	45	30	13	53
Select Energy Services	WTTR	UW			0.42	0.97	0.55	(0.91)	(0.65)	(0.45)	117	258	183	12	22	33	(3)	232	204	123	36	30	(99)	(165)	(110)	(23)	(23)	(18)	(102)	67	94	101	13	13
Small/Mid Cap Avg				**5%**																														
NOW Inc.	DNOW	N			(0.27)	0.36	0.24	(0.46)	(0.20)	(0.05)	7	109	87	(15)	(2)	22	(115)	73	224	147	(11)	20	(4)	(11)	(12)	(9)	(11)	(9)	(119)	62	212	138	(22)	11
MRC Global	MRC	OW	$7	2%	0.01	0.58	0.43	(0.20)	0.25	0.50	179	280	201	90	100	126	(48)	(11)	242	238	66	97	(30)	(20)	(18)	(11)	(12)	(12)	(78)	(31)	224	227	54	85
Energy Distribution Avg				**2%**																														
Helmerich & Payne*	HP	N	$21	(16%)	(0.88)	0.50	1.52	(2.60)	(2.88)	(2.02)	423	657	743	152	68	180	567	682	758	422	96	179	(407)	(571)	(308)	(118)	(98)	(150)	160	111	450	304	(2)	29
Nabors Industries	NBR	UW	$5	(93%)	(80.90)	(60.10)	(70.13)	(78.58)	(64.10)	(49.85)	544	759	805	558	491	627	63	326	685	388	226	341	(574)	(459)	(428)	(200)	(194)	(206)	(512)	(133)	257	188	32	135
Patterson-UTI Energy	PTEN	UW			(0.81)	(0.35)	(0.98)	(2.28)	(2.25)	(2.00)	546	802	598	215	131	177	301	731	696	318	178	218	(502)	(641)	(348)	(150)	(131)	(146)	(201)	89	349	168	47	72
Onshore Drilling Avg				**(54%)**																														
Transocean	RIG	UW			(0.45)	(0.79)	(1.45)	(0.80)	(1.40)	(1.40)	1,214	1,065	934	918	678	665	1,144	558	340	160	4	97	(497)	(184)	(387)	(344)	(1,270)	(220)	647	374	(47)	(184)	(1,266)	(123)
Offshore Drilling Avg																																		

Source: J.P. Morgan estimates, Bloomberg Finance L.P.
Note: Prices as of December 15, 2020.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

"Hunger Games": OFS Can't Afford to Stay Home and Sustain Itself This Cycle

The Long Path Back to a Lower "Normalized"

As the upstream continues to "do more with less" we think earnings power for the group will be eroded cycle/cycle once again

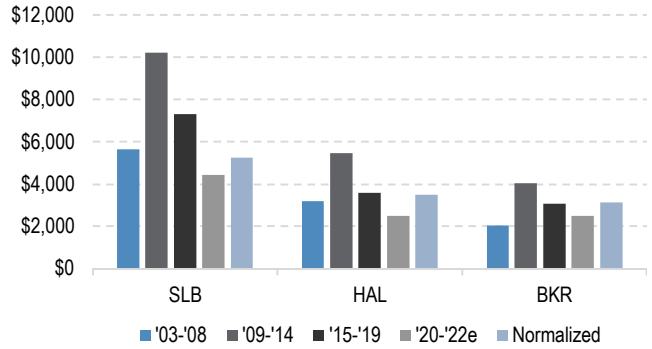
With our expectation that the sector's traditional addressable markets and earnings power will shrink for the second consecutive cycle, Oil Services & Equipment companies are in a very difficult position to generate decent returns. 2020's pandemic has been devastating for the industry, but a silver lining has been the efficacy of massive cost-out programs that have somewhat softened the impact of generationally low levels of activity on margin profiles. Yet the path to even a lower "normalized" level of profitability and cash generation looks to be years away (see The View to 2025). After 2020's balance sheet liquidation allowed for strong free cash flow, the next few years look pretty tight for most.

The market has shown a willingness to pay up for optionality in this sector, and when adjusting for lower valuations cycle/cycle, we believe the market is already discounting mid-cycle metrics that approximate the 2015-2019 cycle. While such an outcome is not unreasonable, to "pay up" for it today leaves an unfavorable risk/reward in our view. Directionally activity and oil prices should be upward sloping the next few years, a necessary but insufficient condition for the stocks. Recall that the same was true from 2016-2018, yet as Street estimates were relentlessly revised lower (A Watched Pot Never Boils), the group experienced inevitable multiple compression (Between the Devil & the Deep Blue Sea) as the stocks rebased to the lower earnings trajectory.

Buy the bear, sell the bull: sensitizing next cycle's "normalized"

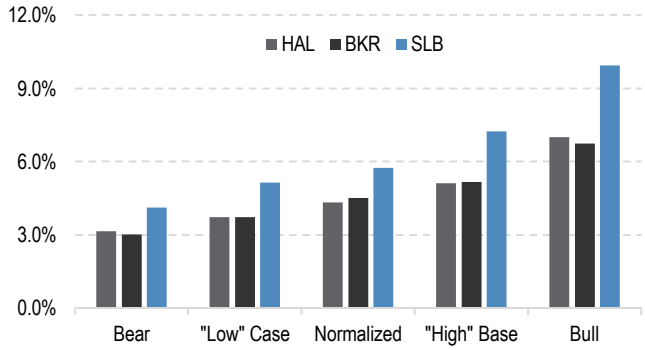
Lacking a cycle/cycle growth narrative, we believe OFS companies need to be managed for FCF and will be valued as such. Therefore we've transitioned our valuation methodologies to normalized FCF/EV yields, with a framework that evaluates a range of outcomes, from bearish to bullish. We think the stocks can offer good value when the market is pricing in the bear case as normalized, but when the upper-end of the base case range is already being discounted (thus leaving the bull case as the upside), we'd recommend reducing positons.

Figure 18: Big Three EBITDA by Cycle ($mm)



Source: Company reports, J.P. Morgan estimates. Note: does not make adjustments for acquisitions/divestitures (e.g. SLB-CAM).

Figure 19: Big Three FCF/Current EV Yield by Scenario



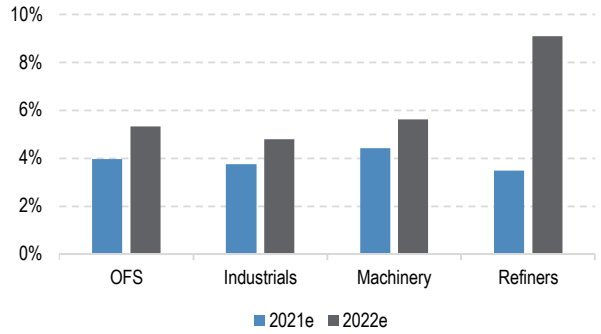
Source: Bloomberg Finance L.P., Company reports, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

OFS Must Compete with Cyclicals for Generalists' Attention

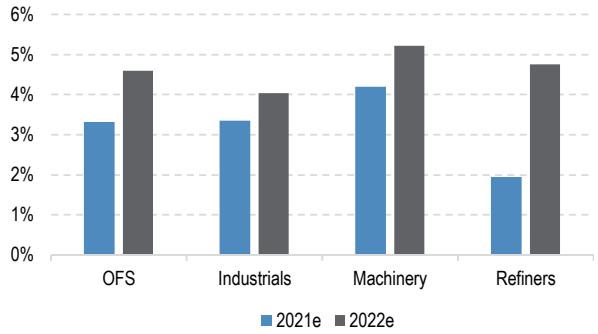
A year ago (when the group was still in 'late cycle') we noted that OFS stocks needed to pull all levers to harvest cash to offer competitive FCF yields when compared to other cyclicals in order to garner investor interest. With the downturn forcing cost-out initiatives and some consolidation (and bankruptcies to date), as activity normalizes we think parts of our coverage could exhibit attractive yields (through a combination of higher numerators…and lower denominators). Following the aggressive rally off the March lows we remained defensive with the view that buying these stocks on heightened expectations was a negatively skewed bet considering the duration required to justify the move. Depending on the specific factors, we're anchoring our price targets to FCF/EV yields between MSD to HSD as "full" valuations; therefore, HSD/LDD yields are needed to find attractive entry points. One point of clarity: we define FCF as CFO-capex but do not add back interest expense when comping to the EV.

Figure 20: OFS 2021/2022 FCF Yields v. Other Cyclicals



Source: Company reports, J.P. Morgan estimates, Bloomberg Finance L.P.

Figure 21: OFS 2021/2022 FCF/EV Yields v. Other Cyclicals

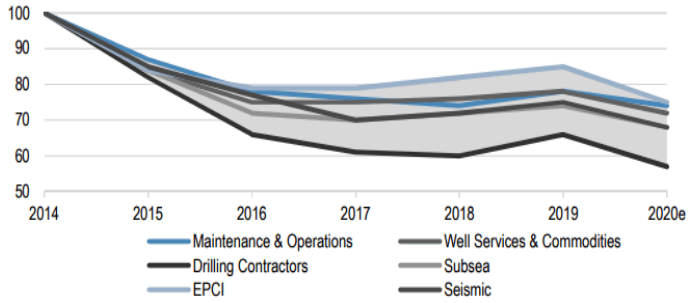


Source: Company reports, J.P. Morgan estimates, Bloomberg Finance L.P.

There's Not Enough Upstream Capex to Go Around

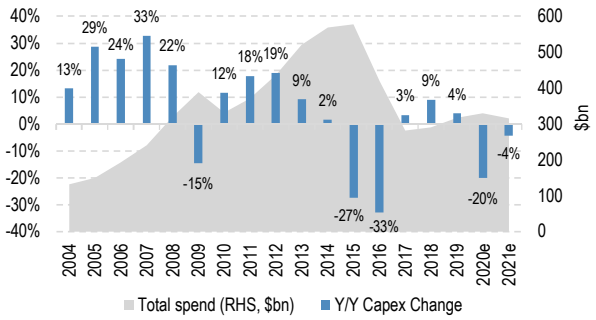
We continue to emphasize next cycle's probability distribution is skewed "base-to-bear", and our mid-cycle framework is towards the lower-bound of our base range. Our "normalized" scenario (see below) assumes NAM activity will average ~27% lower cycle/cycle while international is relatively shielded at -15% (along with further deflation/efficiency headwinds). We have adapted our initial scenarios from the deep dive in June to skew shale oil's "inducement price" higher (an idea we floated in the note) as we think our incremental learnings across U.S. E&Ps and their IOC counterparts lend credence to the idea that E&Ps will require a higher price to add meaningful activity above maintenance and such an outcome is the most efficient for the oil market to balance from a deficit position.

Figure 22: OFS Service Cost Deflation (2014=100)



Source: Rystad, J.P. Morgan estimates.

Figure 23: Upstream Capex ($bn, RHS) and Y/Y Growth (%, LHS)



Source: Company reports, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 4: JPM Normalized Scenarios for the Coming Upstream Cycle

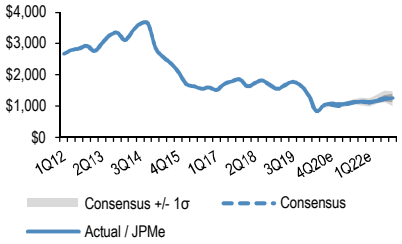
	Prior Cycles		Normalized Cases				
NAM	**'09-'14**	**'15-'19**	**Bear**	**"Low" Base**	**Normalized**	**"High" Base**	**Bull**
Average WTI Price	$87	$53	Low-$40s	Low-$50s	Mid-$50s	Low-$60s	$70+
Annual Oil Production Growth (mmbbl/d)	+750	+1,038	Flat	+500	+600	+1,000	+1,500
Average U.S. Land Rig Count	1,712	870	400	550	635	750	1,000
Average U.S. Oil Rig Count	961	697	330	480	550	660	900
Average U.S. Gas Rig Count	751	172	70	80	85	90	100
Average U.S. Frac Spread Count		346	163	225	250	300	425
International							
Average Brent Price	$96	$58	High-$40s	High-$50s	Low-$60s	High-$60s	$80+
Average Int'l Rig Count	1,186	1,033	800	850	880	950	1,050
Average Int'l Land Rig Count	881	802	650	675	690	725	800
Average Int'l Offshore Rig Count	305	230	150	175	190	225	250

Source: Baker Hughes, Genscape, J.P. Morgan E&P Research, J.P. Morgan OFS estimates.

The Market Is Already Crediting a Pretty Decent OFS Cycle

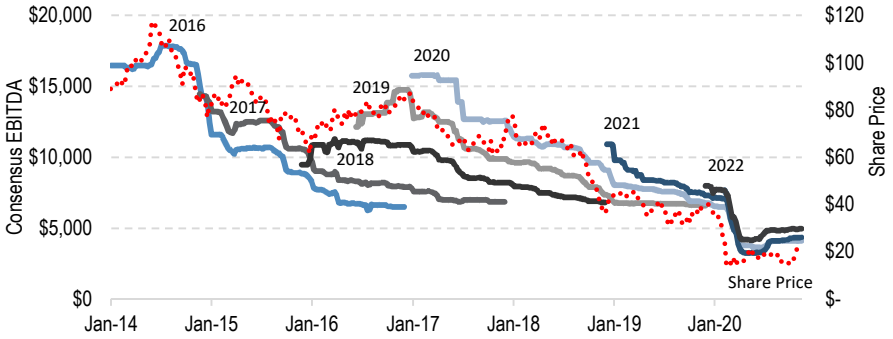
Sparked by positive vaccine developments, the market rally has carried the OSX ~70% higher (v. SPX +12%) since its most recent bottom in late October, with WTI rising only ~30%. Even so, the OSX is underperforming the commodity by ~20% YTD, and we point to the figure below showing relentless negative EBITDA revisions for SLB over time driven by an asymmetric relationship between earnings and WTI performance (thanks to secular deflationary pressures from technology). As the market pulls forward several years of growth and attempts to benchmark to prior cycles we stay grounded in our thesis that the upstream will require less activity cycle/cycle as efficiency gains persist. Even if revisions seem unlikely to be as negative as in the prior cycle, we see little scope for material upward ones either.

Figure 24: Historical SLB Quarterly EBITDA



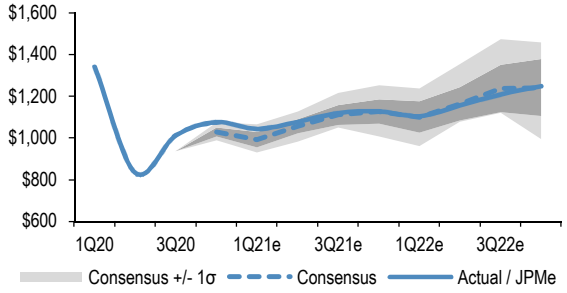
Source: Company reports, Bloomberg Finance L.P., J.P. Morgan estimates.

Figure 25: SLB Consensus EBITDA (LHS) v. Share Price (RHS)



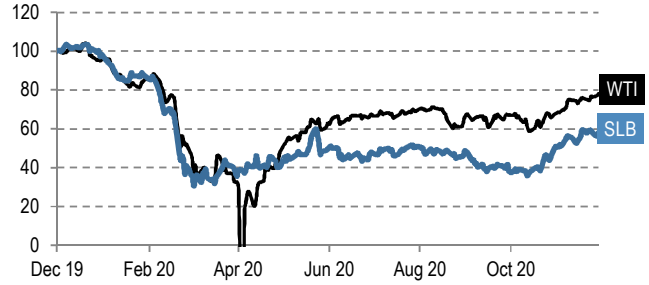
Source: Bloomberg Finance L.P., J.P. Morgan estimates.

Figure 26: SLB Quarterly EBITDA: JPMe v. Consensus



Source: Company reports, Bloomberg Finance L.P., J.P. Morgan estimates.

Figure 27: SLB shares bounced hard but still down materially YTD



Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Leaving New Energy as a Potential Escape Route

The pivot to new energy is daunting, and many will not survive the journey intact; still, some won't have a choice but to throw their hat in the energy transition ring

Many companies across our coverage have their hands in the New Energy cookie jar (which for several has been the case for years now). Subterranean expertise not only lends itself to the more obvious avenues of geothermal and carbon capture, but the engineering prowess of OEMs and offshore-oriented service providers is applicable to hydrogen, wind and of course, LNG, an important transition and destination fuel in our view; the primary absence in our coverage is exposure to the solar market (which has become more commoditized as it's scaled). We dive into the company-specific nuances later in this report but in general, oilfield service and equipment providers have the ability and increasingly the market positioning to help enable the energy transition globally. The challenge we continuously return to is the path to materiality for the sector. Excluding LNG where our coverage is well established, the revenue mix of new energy end markets remains small (and trails behind European peers), but growth opportunities are available in the years (and *decades*) to come.

Table 5: OFS New Energy Exposures

	Hydrogen	LNG	Wind	Solar	CCS	Geothermal	Biofuels
NAM	BKR	BKR	NOV		BKR	BKR	CLB
	FTI	FTI	OII		FTI	CLB	FTI
	SLB	CLB	DRQ		TS	SLB	NOV
	TS	NOV	OIS		CLB	TS	DNOW
	DNOW		RIG		DRQ	HAL	
			DNOW		RIG	HP	
						NOV	
						DNOW	

Source: Company reports, J.P. Morgan estimates.

Top Picks into 2020: Pair Defense with Select NAM Offense

After (another) yearend beta rally, we want to be balanced in our exposures, allowing for the continuation of the completions recovery trade in North America (e.g., **NEX**, proposed in our Fall Playbook) while also staying defensive (e.g., **BKR**, **FTI**, **NESR**) for what we see as an eventual fade as the timing and magnitude of the recovery in oil services fundamentals relative to the economic reopening disappoints. Given our bias remains bearish in offshore, our top Underweights are levered to long cycle deepwater (e.g., **RIG**, **OII**). We also have a clear balance sheet bifurcation between the groups, with ballast balance sheets among our OWs against challenged leverage positions among our Underweights (including **NBR**).

Table 6: JPM OFS Top Picks

Company	Ticker	Rating	PT	Up/Down	JPM View
TechnipFMC	FTI	OW	$16	61%	Advantaged player in subsea and LNG end markets with solid new energy exposure featuring an attractive valuation and a defined value creating catalyst in the upcoming spin
NexTier Oilfield Solutions	NEX	OW	$5	36%	Combines strong balance sheet, solid management and good operational track record at a relative discount to peers; 2021 execution can drive mean reversion to peers
National Energy Services Reunited	NESR	OW	$11	12%	Offers idiosyncratic growth as a pure play in MENA with margins and capital discipline supporting our 'growth plus cash' thesis at only a NAM onshore valuation
Baker Hughes	BKR	OW	$23	4%	Long and late cycle exposures a relative benefit in underwhelming E&P capex recovery with advantaged industrial, LNG and new energy franchises and strong balance sheet
Nabors Industries	NBR	UW	$5	-93%	Heavy debt burden and challenged FCF prospects in both its U.S. and international operations leaves the equity disadvantaged in our view
Oceaneering	OII	UW	NR	N/A	With elevated debt in an unfavorable environment for offshore services we think OII is likely to lag its peers in recovery
Transocean	RIG	UW	NR	N/A	Despite proven operational performance we don't expect offshore drilling fundamentals to allow RIG to successfully fix its capital structure without entering restructuring like the rest of the market

Source: Bloomberg Finance L.P., J.P. Morgan Estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

10 Things We're Focused On in 2021

1. With the bar materially raised, will Street numbers be good enough?

Street estimates look achievable to us in 2021, particularly early in the year with some macro tailwinds on reopening. However, as 2022 (and 2023) get closer, we're curious to see if the group can hold its recent gains without more positive revisions.

2. How long is "flat the new up" in shale, and can OFS generate cash?

While we model sequential progression in 1H21 in NAM and 2H21 abroad, we expect both to be lower y/y, with limited scope for growth in 2022. After 2020's WC liquidation, FCF risks getting pretty thin, but is a source of potential differentiation.

3. Is NAM onshore activity much different at low $50s WTI v. low $40s?

We think shale is still capable of meaningful production growth if needed, but will require a higher inducement price due to superseding cash flow commitments. As a result, L-48 activity may not look materially different within this WTI band.

4. Is the sector at risk of 2017 redux if incremental margins disappoint again?

Much of the sector's market cap demise was tied to the negative revision cycle in the 2017-2019 upturn thanks to disappointing margin progression. OFS has again promised strong incrementals and must deliver to prevent negative revisions.

5. Can the frac market earn respectability and investability via discipline?

With meaningful scrapping (~40% of nameplate) and consolidation (top five control two-thirds of hhp), frac's market structure is improving. Frac leaders need to be disciplined on tendering and e-fleet contract terms to earn investors' trust.

6. Can anyone in OFS break into New Energy to earn a green multiple?

We doubt there's much any company in OFS can do in 2021 to earn a green-ish multiple, unless one pursues the AKSO spin route (which is possible, e.g., FTI). Still, with limited opportunities in upstream, it's worth pursuing long-term options.

7. Does international activity really turn in 2H21, or is 2022 more realistic?

The diversifieds expect a trough forming in 1H21 int'l activity, with a ramp in 2H21 on the back of economic reopening and improving oil demand. We think this is directionally correct but at risk of disappointing the market, with 2022 looking better.

8. Will small-cap OFS "block up" to gain scale and meaningful market cap?

With materially lower addressable markets, inconsequential market caps and no other buyers, we think our small caps have no choice but to scale up together to take out cost and regain relevancy to the capital markets. Admittedly finding the right configurations isn't easy, but we believe the cycle's pressures leave few other outs.

9. Can offshore drillers figure out 'the delicate dance' of predator or prey?

Speaking of consolidation, most of the offshore rig fleet is in restructuring. We believe our uninspiring activity assumptions demand meaningful consolidation and rig scrapping, ideally down to 2-3 sizable competitors in the floater market and most jackup markets. Otherwise we struggle to see how the economics work offshore.

10. How long will the market pay up for last cycle's "normalized"?

Last cycle, it took ~2.5 years from the original Brent trough for the buy-side to capitulate on the prior cycle's "normalized" earnings. Though offering the benefit of the doubt at present, we expect the market to give OFS a shorter leash this time.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

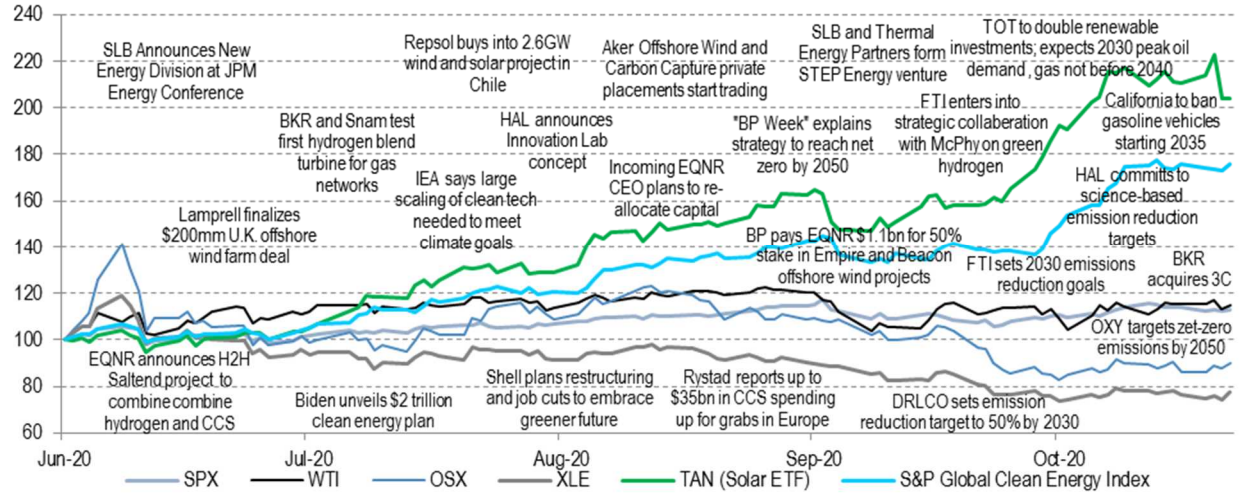
Catching Fire: To Rise from Upstream's Ashes, OFS Must Embrace New Energy

With Options Limited at Home, Go to Where the Growth Is;

With a mature upstream limiting growth opportunities, OFS needs to take a long, hard look at new energy channels

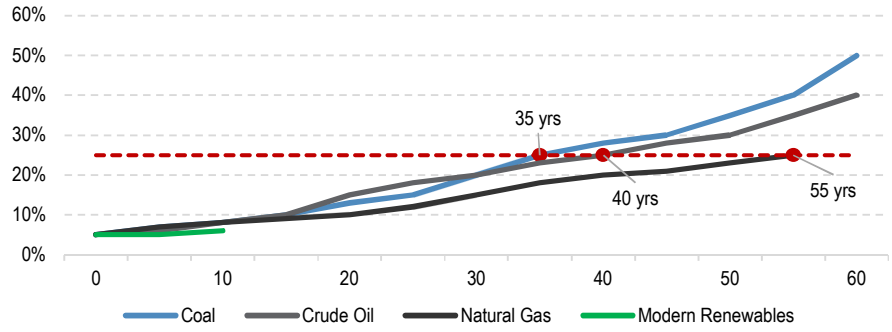
For a sector accustomed to breakneck growth, Oil Services' transition to a mature upstream market has been a challenging one. As we laid out earlier in this report, we expect the upstream to continue to "do more with less", leading to lower cycle-over-cycle activity and thus a smaller addressable market for services and equipment. As a result, we think it would be prudent for competitors in this sector to devote more effort to exploring tangential new energy channels that could be sources of potential growth. While we're giving New Energy more attention than in the past editions of our Outlooks, we also don't want to overstate the potential impact in the near- or even medium-term. Most of the opportunities are niche today, but offer the potential for much larger addressable markets a decade out. Once again, our long-held preference for equipment exposures over services bears out in this situation; we see OEMs as among the best positioned to not only participate, but hopefully capture a decent share of the economics where unique IP can be developed and monetized.

Figure 28: ESG Recap v. Energy Stock Prices since June



Source: Bloomberg Finance L.P., Company reports, Upstream.

Figure 29: Total Years for Energy Sources to Supply ~25% of Global Demand



Source: V. Smil, BP, JPMAM.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Lots of overlap between 'old' and 'new' energy, especially offshore

While enthusiasm for the energy transition is accelerating, we emphasize scale will take time (i.e. decades) as it did with previous transitions (see above). The OFS sector has developed material engineering prowess over the past two decades (and in the last one in particular). Examining the prospects across the value chain in new energies reveals many opportunities for "old" energy expertise to be applied to "new." For our offshore-oriented names, traditional drilling and subsea equipment can be utilized for offshore wind (e.g., NOV, OII) and CCS infrastructure (e.g., DRQ, FTI). As Europe attempts to ramp renewable hydrogen, the transition from blue to green also taps into some niche exposures among our coverage; for example, BKR's leading gas turbine franchise gives it exposure to the hydrogen market no matter how it evolves. Onshore, the call to lower the cost curve for geothermal drilling could be met by those with subterranean expertise (e.g., SLB, BKR, CLB).

Figure 30: NAM OFS Renewable Energy Exposure

Company	Ticker	Exposures
Schlumberger	SLB	Geothermal (Celsius and STEP Energy), hydrogen (Genvia)
Baker Hughes	BKR	Large LNG exposure, CCS, full rainbow of hydrogen (Nova LT turbines) and emission reduction tech/processes
Halliburton	HAL	Geothermal, low-carbon technology (Halliburton Labs)
Tenaris	TS	Hydrogen, Geothermal, and OCTG products for CCS infrastructure
National Oilwell Varco	NOV	Offshore wind installation vessels, LNG, biofuels, geothermal (ION cutter technology)
TechnipFMC	FTI	Large LNG exposure, hydrogen, CCS potential, de-carbonizing subsea, biofuels
Helmerich & Payne	HP	Geothermal
Transocean	RIG	Potential offshore wind and drilling storage reservoirs for CCS
Core Laboratories	CLB	CCS, LNG, biofuels, and potential geothermal
Dril-Quip	DRQ	Potential pipelines for CCS and subsea systems/trees for offshore wind
Oceaneering	OII	ROV and route clearing services for offshore wind
NOW Inc.	DNOW	Provides products to end-markets for: biofuels, offshore wind, geothermal, hydrogen
Oil States	OIS	Potential offshore wind and subsea mining

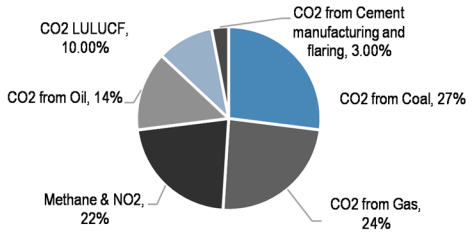
Source: Company reports.

The Mandate Is Clear: "Higher Returns, Lower Carbon"

The two goals cannot be sustained as mutually exclusive; both are needed

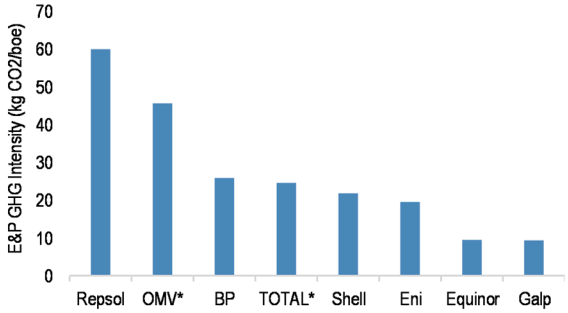
For OFS to participate in New Energy, delivering lower carbon solutions will not be enough, as producers need to improve their returns as well. European oil companies are furthest along in plans to shift portfolios to new energies featuring low carbon return targets of +10%. The U.S. majors appear wary of such dramatic commitments while independent E&Ps are mostly not looking to diversify away from traditional O&G. Meanwhile the standouts among the coverage of our European colleagues include Total, Repsol, Equinor and Galp, all offering >5% of 2025 EPS from low carbon exposures and plans to ramp over the next decade.

Figure 31: GHG Emissions Increasingly in Focus, % of 2017 anthropogenic emissions



Source: J.P. Morgan EU Oils Equity Research, company reports.

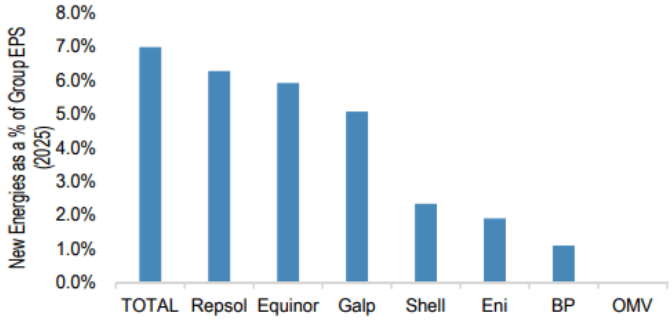
Figure 32: Upstream GHG Emission Intensity



Source: J.P. Morgan EU Oils Equity Research, company data.

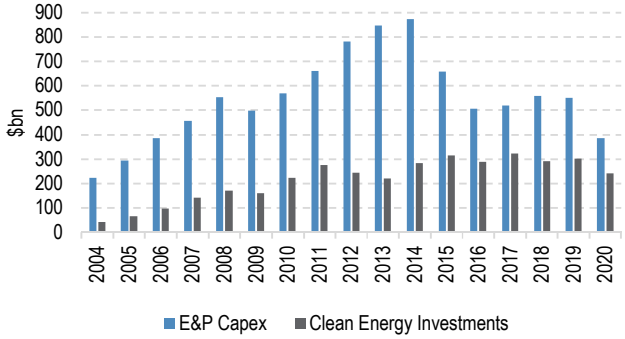
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 33: Low Carbon Financial Materiality (% of 2025 EPS)



Source: J.P. Morgan EU Oils Equity Research, company data.

Figure 34: Historical E&P Capex v. Clean Energy Investments

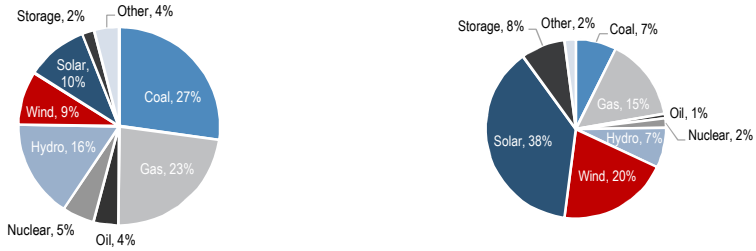


Source: Rystad, BNEF.

New energy growth exciting but O&G spend still outsized

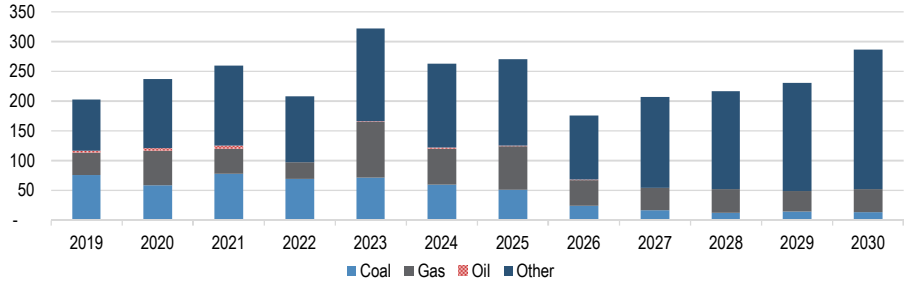
Global installed energy capacity is expected to almost triple in the next 30 years to keep up with demand and renewables could potentially account for the majority of the mix by 2050 (see below). Fueled by emerging markets growth, oil and gas demand should continue to grow, and while we think E&P capex is lower cycle over cycle (and perhaps half of the 2014 peak) thanks to productivity and efficiency gains, upstream spend will likely still far exceeds capital deployed into renewables near-term. Further, even a materially shrunken upstream addressable market will dwarf what our coverage can carve out of the new energy supply chain even in the medium term. As we highlight in this report, there is potential for our coverage to grow new energy exposures from very low bases, but it's too early to expect the market to assign much value to these ambitions, even as we encourage the strategic pivot.

Figure 35: Global Installed Capacity Mix, 2020 v. 2050



Source: BNEF.

Figure 36: Global Gross Capacity Additions by Source (GW)



Source: BNEF.

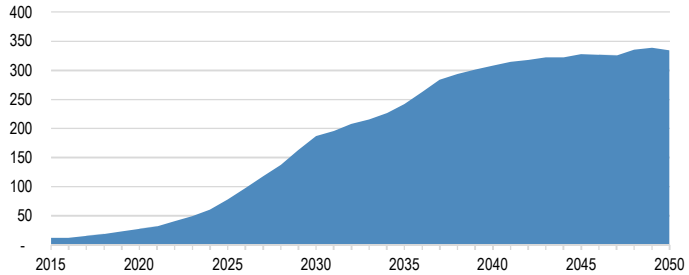
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Offshore Wind: A Promising Future, but Not Expecting Scale Just Yet

While global scale for offshore wind may not come immediately, we see a vast opportunity set for subsea players in OFS

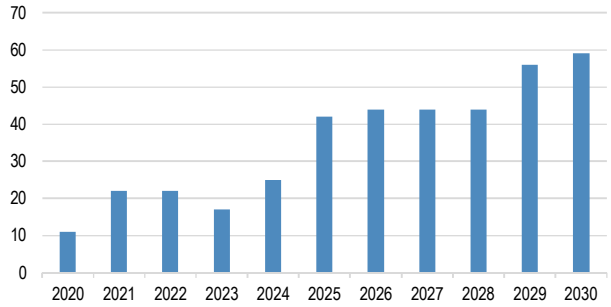
During our JPM Energy Technology Tour, FTI referred to offshore as the "new frontier" for energy development; for our OFS coverage, we see meaningful offshore wind prospects resulting from the buildout of existing subsea infrastructure. Among offshore-oriented players, the opportunity set today favors Europe with installations there expected to expand +45% by 2030, but we expect contributions from the U.S. to become more meaningful after 2025. SUBC has been the most expansive builder among our global OFS coverage (covered by James Thompson), indicating the sizable market which could lay ahead (see below). While we do not anticipate scale near-term given the extensive infrastructure buildout required, we think those able to apply existing offshore expertise to offshore wind will be able to find a decent new source of revenue while core offshore upstream activity remains challenged.

Figure 37: Offshore Wind Projected Cumulative Installed Capacity (GW)



Source: BNEF

Figure 38: Global Anticipated Offshore Wind Capex ($bn)



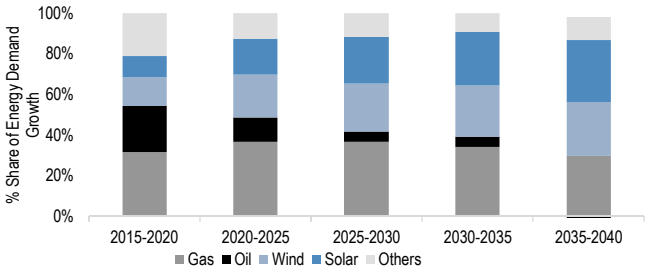
Source: J.P. Morgan European O&G Equity Research, company reports.

NOV has indicated that its Max digital platform could be implemented for its offshore wind offering. A single wind jackup kit represents an opportunity of up to ~$70mm for the company, with additional taller towers potentially driving it higher in the future. Importantly, **FTI** has demonstrated that companies can also implement offshore wind into their own de-carbonization goals; with its goal of bringing renewables offshore through the Deep Purple project, the company is looking to offshore wind and wave energy to power its all-electric subsea infrastructure.

Figure 39: NOV's Customized Offshore Wind Jackup for Shimizu

Source: Company presentation.

Figure 40: Global Energy Demand Growth by Source



Source: J.P. Morgan European O&G Equity Research, company data.

Among small-cap OFS, OII provides ROV and route clearing services, and **DNOW** provides products to end-markets for offshore wind. We also see OEMs **OIS** and **DRQ** and offshore driller **RIG** as examples of those which could leverage existing expertise in traditional offshore drilling and subsea for offshore wind in the future.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

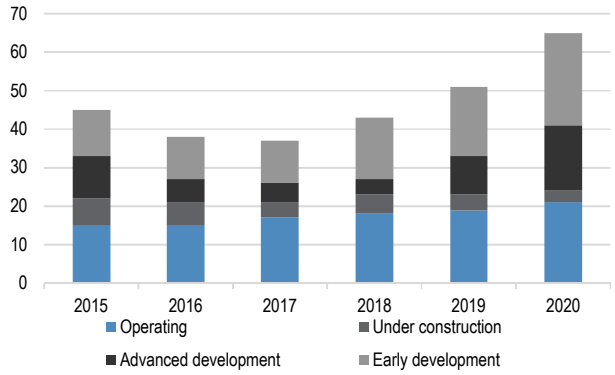
Carbon Capture: OFS Well-Suited Across the Value Chain

BKR appears to be the best-positioned in our coverage to become a technological leader in CCUS

CCS is critical to most long-term de-carbonization frameworks…

Given the challenges of building out the required infrastructure to scale renewable energy sources, a focus on cutting emissions through carbon capture and storage (CCS) is a significant opportunity for those already technologically equipped in our view. CCS is expected to play a substantial role in achieving 2050 de-carbonization goals, however the pace looks to be highly dependent on carbon pricing (i.e. carbon tax regimes) which has been driven higher recently by stricter climate policy in the EU (no uniform global price exists). Given this, energy producers are increasingly incorporating future carbon prices into current project economics.

Figure 41: World-Scale CCUS Facilities



Source: IEA.

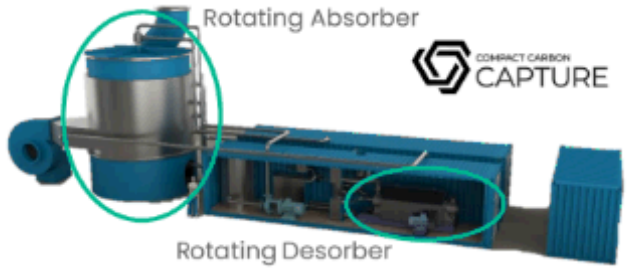
Figure 42: ICE Carbon Futures Europe YTD (Euros Per Ton)

Source: Bloomberg Finance L.P.

…but whether the technology can scale economically is an open question

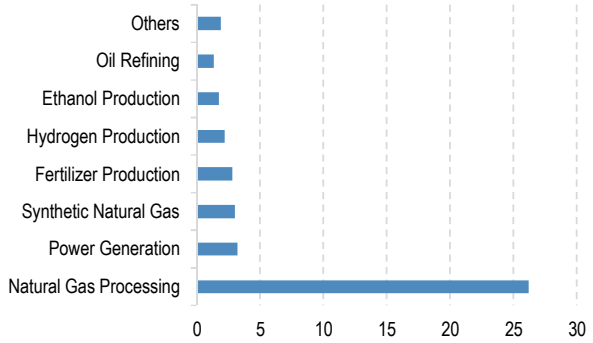
BKR has indicated that ~750 Mt of annual CCUS capacity will be needed by 2030 to achieve the IEA's Sustainable Development Scenario and the Paris Agreement will require 28 GT captured; there is currently ~40 Mt in operation today. Without CCS, the company forecasts the costs to meet the Paris Agreement will be ~70% greater. BKR appears to be one of the most technologically capable companies in our coverage to become a low-cost CCS provider with opportunities across the full value chain, and is helped by its recent acquisition of Compact Carbon Capture (3C). With 3C, BKR will be able to use the company's rotating beds (synergistic with BKR's rotating equipment expertise) instead of static columns, resulting in lower capital intensity and a carbon footprint that is up to ~75% smaller (see below). The company is currently actively involved in 20 active projects (14 in EU); though, it has indicated it sees the U.S. as being more legislatively favorable going forward.

Figure 43: Amine Plant Using 3C Technology



Source: Baker Hughes presentation.

Figure 44: Global CO_2 Capture Capacity by Source (MMT/year)

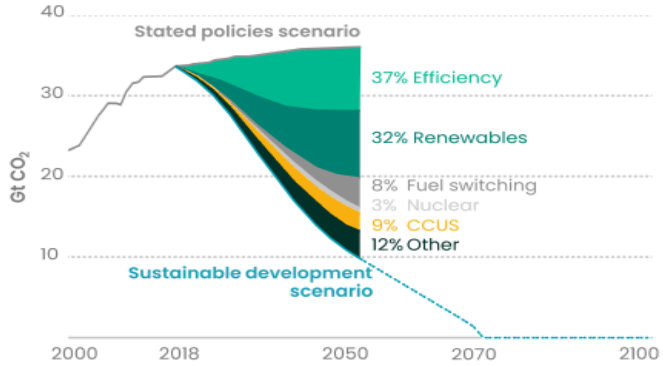


Source: Global CCS Institute, BNEF.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

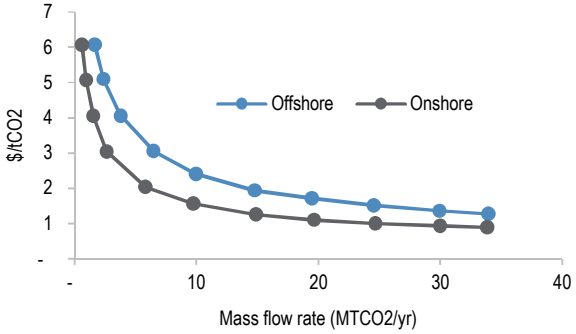
For offshore carbon capture projects, **TS** has the opportunity to win contracts if operators choose to build out new pipelines rather than utilize existing infrastructure. The Acorn CCS project in the North Sea, backed by Shell, Total and Chrysaor, plans to capture 300-400ktpa of CO_2 in its first stage with eventual capacity of 2mmtpa. TS is currently in conversations and the project could represent an OCTG opportunity of ~30k tons. While the work scope does not require the highest quality of product, given the process requires injecting gas into the reservoir, it calls for premium pipe.

Figure 45: Global CO_2 Emission Reductions



Source: Baker Hughes presentation, IEA.

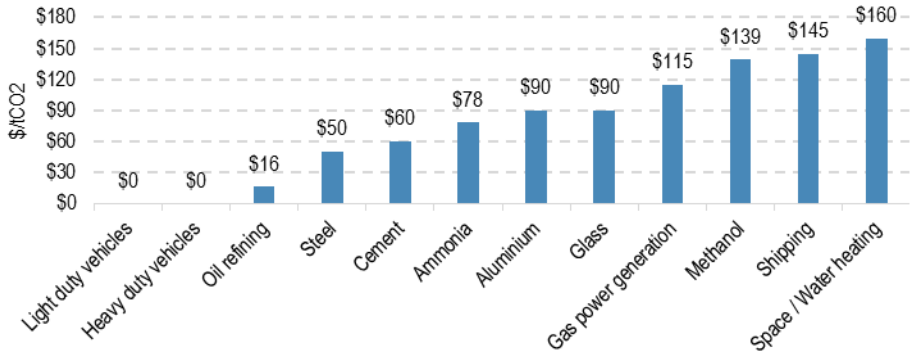
Figure 46: CO2 Transport Cost for Pipeline Transport by Type



Source: IPCC, BNEF.

Though not a larger near-term opportunity, we think **FTI** has significant CCS potential by incorporating capture technologies in the second iteration of its Deep Purple subsea system. The company already has a strong position in the grey hydrogen market, with some exposure to blue hydrogen (grey plus carbon capture). Opportunities also exist for other smaller players among our coverage to use their existing expertise for the buildout of the required infrastructure. The CCS process requires special pipelines for the transportation of CO_2, and **DRQ** has indicated it could become engaged in the manufacturing of these; similarly, **RIG** has the potential to be involved with the drilling of subsea storage reservoirs. Utilizing its laboratory expertise, CLB has helped investigate CCS for the Carbon Net Project in Australia.

Figure 47: Carbon prices required for hydrogen to compete with the cheapest fossil fuel in each use case, 2050



Source: BNEF.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

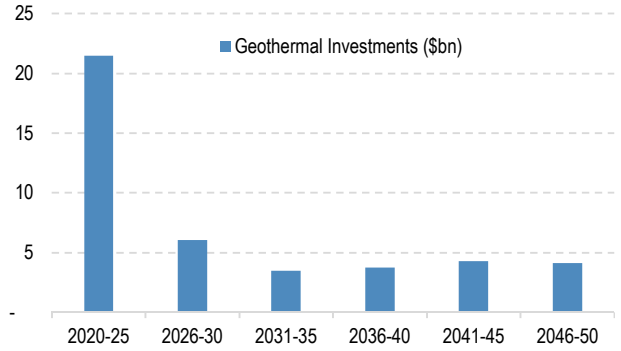
Geothermal: OFS Expertise Required but Technology Remains in Early Stages

OFS has already carved out its niche in geothermal but path to materiality is less clear

Growth rates outsized thanks to "law of small numbers"; can geothermal scale?

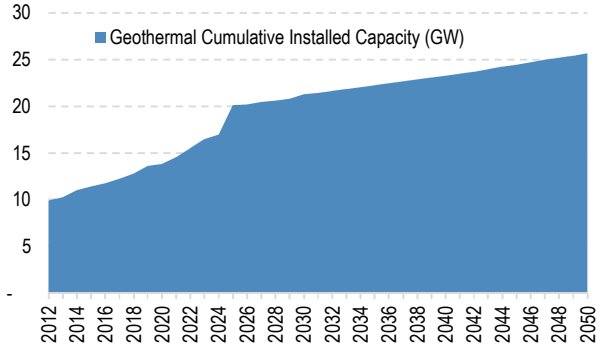
As of 2020, geothermal accounts for 88 TWh of global electricity generation, less than 0.4% of the global mix or 1.2% of the global renewables mix. While the current base is small, it has outsized growth potential: the U.S. Department of Energy estimates that geothermal power generation in the U.S. could increase ~26-fold, representing 60GW of installed capacity by 2050. We note that projections are wide-ranging with BNEF's expectation for significantly lower capacity *globally* (see below). An obstacle to a more optimistic forecast is the long-term nature of geothermal projects, which require significant up-front capital, stemming from exploratory and well construction costs given lengthy drilling processes dealing with challenging rock formations and such high temperatures.

Figure 48: Planned Geothermal Cumulative Investments in New Capacity



Source: Bloomberg NEF.

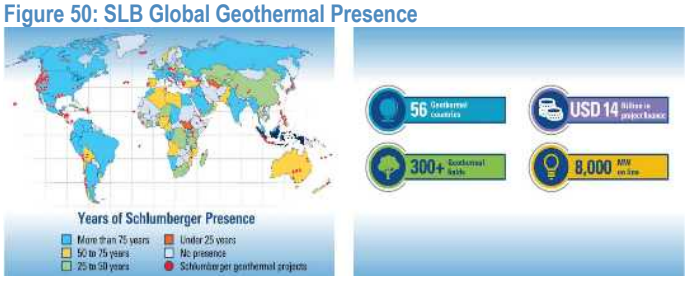
Figure 49: Projected Global Geothermal Installed Capacity



Source: Bloomberg NEF.

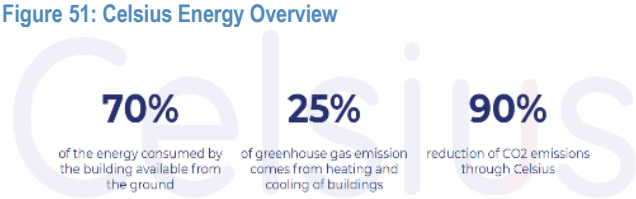
Still, several among our OFS coverage clearly have subterranean expertise from traditional O&G drilling and evaluation and are being called upon to problem solve and lower the cost curve: **SLB** and **CLB** are the current standouts in our view. While Schlumberger is in early stages, it's still the most advanced in our coverage with its Celsius Energy JV, trying to ramp geothermal energy as the next major renewable power source after wind and solar. SLB is contributing its subterranean and drilling expertise to lower costs to deploy heating and cooling to virtually any building, anywhere in the world. Buildings require a considerable amount of energy (contributing 25% of global GHG emissions), making energy usage and CO_2 emissions increasingly a primary focuses of development planners. We also think CLB is well-positioned to easily pivot from traditional oil and gas to use its "core" competencies to provide lab work and analysis for future geothermal project.

Figure 50: SLB Global Geothermal Presence



Source: Schlumberger.

Figure 51: Celsius Energy Overview

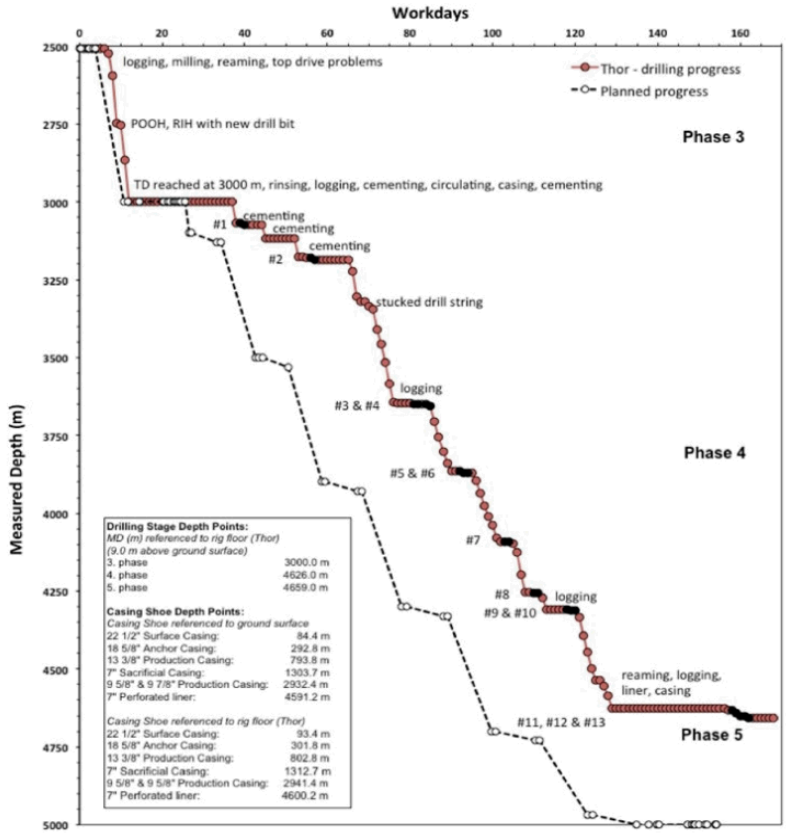


Source: Celsius Energy.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

BKR deployed its drilling equipment for the Iceland Deep Drilling Project (IDDP-2 well) in 2017, which had a depth of 4.5km and temperature of 426°C (see below). Thirteen coring attempts were made below 3km by coring engineers at Baker Hughes and ACS Coring Service. As geothermal projects gain traction this is clearly a market where CLB's expertise can be applied. **NOV's** ReedHycalog business offers its Phoenix Series Drill Bits specifically for geothermal drilling applications. NOV says its products have drilled the longest and fastest intervals for geothermal wells worldwide, citing a 67% higher penetration rate with a single bit in New Zealand and drilling 8% farther and 36% faster in an Indonesian operation. As an example, the IDDP-2 well required ~160 days of drilling, so offering differentiated technology to shorten project timelines for operators is key to improving economics.

Figure 52: Drilling Progress of IDDP-2, Black Dots Represent Core Runs



Source: Stanford University's Workshop on Geothermal Reservoir Engineering, Weisenberger et al. 2017.

HAL has been involved in geothermal projects since the 1950s, working primarily in APAC and European countries. Halliburton's expertise in project management, drilling, cementing, stimulation, etc. are all required. HAL's GeoESP electric submersible pumps can be used for geothermal energy production. HP announced earlier this year it plans to allocate R&D spend (~$30mm in 2021) to advance its rig automation drilling software which will improve processes in geothermal energy. TS reports a revenue segment called "Industrial and Other" which contains its smaller manufacturing activities in hydrogen (pressure vessels), CCS and geothermal (among others). It currently makes up ~7% of mix and Tenaris has noted its new energy exposures are growing quickly from very low bases (e.g. it has limited sales to TSLA) and it thinks the portfolio is well-positioned to capitalize on infrastructure build-outs. Similarly, **DNOW** also sells products for geothermal activities (e.g. pipes, valves, pump packages).

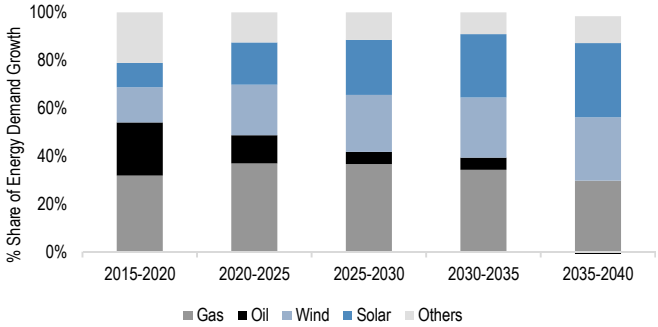
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Aside from LNG, Difficult to Envision What Really Scales in New Energy Near-Term

LNG emits ~45% less than coal, making it the needed solution in the medium term and only benefitting from blue hydrogen adoption

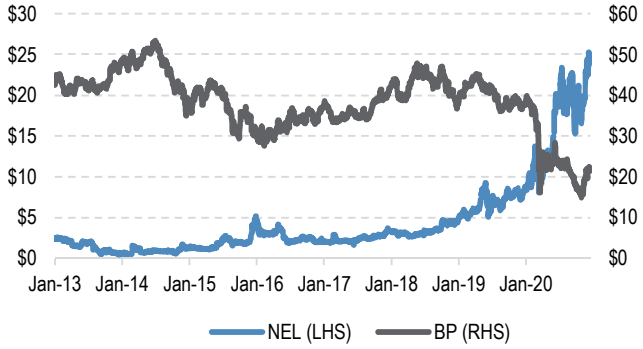
Even for those best positioned for energy transition (e.g., **BKR**, **FTI**, **SLB**), the scope looks quite modest even through the medium-term. We plan to address the energy services pivot to renewables in more detail in the near future, but with the growing appetite for greener energy sources (see NEL chart below, a hydrogen technology supplier, v. BP), we've noticed a more dismissive attitude towards LNG as an investment opportunity. We remind investors of the low hanging fruit that LNG offers in lowering emissions; LNG is ~45% less carbon intensive v. coal according to the EIA. We expect LNG to be the primary driver of global energy demand through 2030 (see below). From there demand risks looks more elevated and becomes a question of how effectively can the industry combine CCS with LNG to achieve ~10x lower emissions compared to grey hydrogen (see below). The next step is the still mostly unproven green hydrogen, so in the interim we continue to view LNG as a critical transition fuel to any material carbon-free replacement; we favor BKR and FTI's exposure to this theme. Both have strong businesses in LNG (i.e. TPS and Technip Energies) and are making progress at solidifying positioning across the hydrogen value chain which will require LNG until green hydrogen proves out.

Figure 53: Global Energy Demand Growth by Source



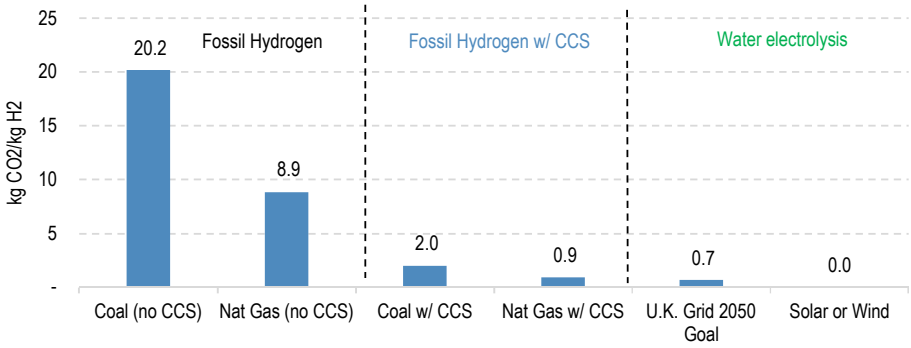
Source: J.P. Morgan European Oil & Gas Equity Research, company data.

Figure 54: NEL v. BP Stock Performance since 2013



Source: Bloomberg Finance L.P.

Figure 55: CO2 Intensity by Hydrogen Production Type



Source: IEA, BNEF. Note: CO2 intensities for hydrogen do not include CO2 emissions linked to the transmission and distribution of hydrogen to the end users. CO2 capture efficiency of CCS process assumed to be 90%.

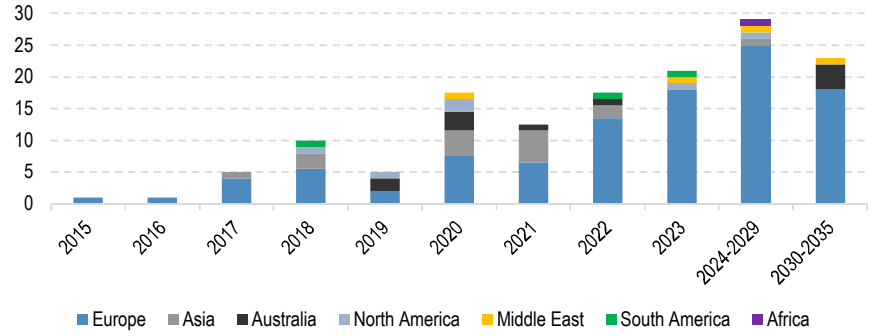
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Hydrogen, Oil Expectations Headed in Opposite Directions

In the wake of this year's epic strategic shifts by European IOCs away from O&G production and the European Union's emphatic push for a zero emission economy by 2050, we've been fairly astonished by the pace of sentiment shift by investors towards the warm embrace of renewables, though not O&G share prices (see below). While energy transition has been gaining momentum for several years, the EU's plan makes plain the path to zero emissions is hydrogen, particularly green hydrogen. Green hydrogen *at scale* still requires belief in the development of innovations that overcome several notable practical limitations to achieving the EU's goals; however, it appears many billions of dollars will be thrown at the problem from a myriad of stakeholders; thus it's a theme that cannot be ignored.

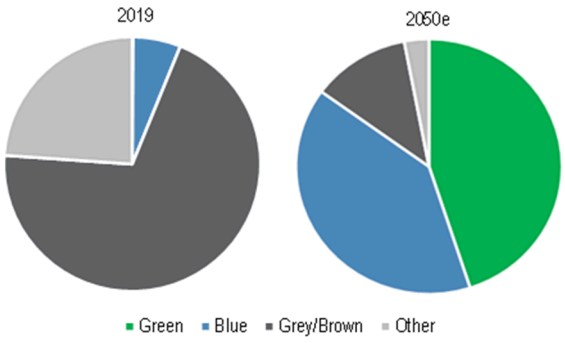
Solar and wind's decades-long path to respectability as energy sources has caught the attention of many hardened, cynical energy investors, and we suspect few want to be caught napping on a hydrogen break-through that could power the next century. We posit that many of those billions will be destroyed in such a pursuit, but potentially to the long-term benefit of humanity, with many parallels to the capital cycle of shale over the past two decades.

Figure 56: Announced Hydrogen Electrolyzer Projects by Start-Up Year, Project Count



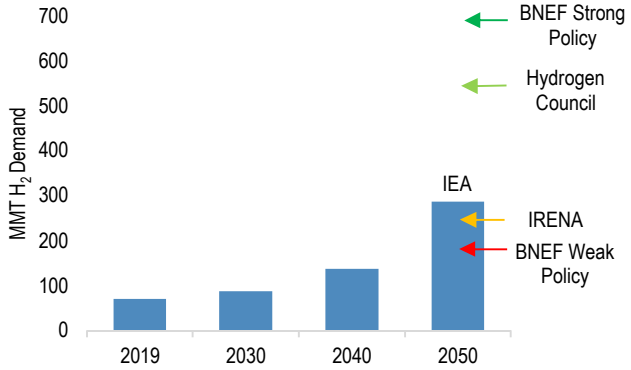
Source: Rystad.

Figure 57: Hydrogen Demand Scenario



Source: Baker Hughes, IEA, J.P. Morgan estimates. Note: Green is ~0.1% in 2019.

Figure 58: Hydrogen Demand Scenario



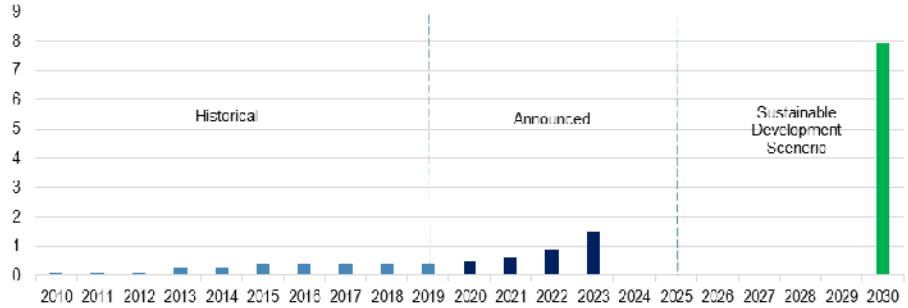
Source: IEA, BNEF, Hydrogen Council, IRENA. Note: BNEF's max scenario: 1,370 MMT.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Hydrogen Demand: Growth to continue as low carbon production ramps

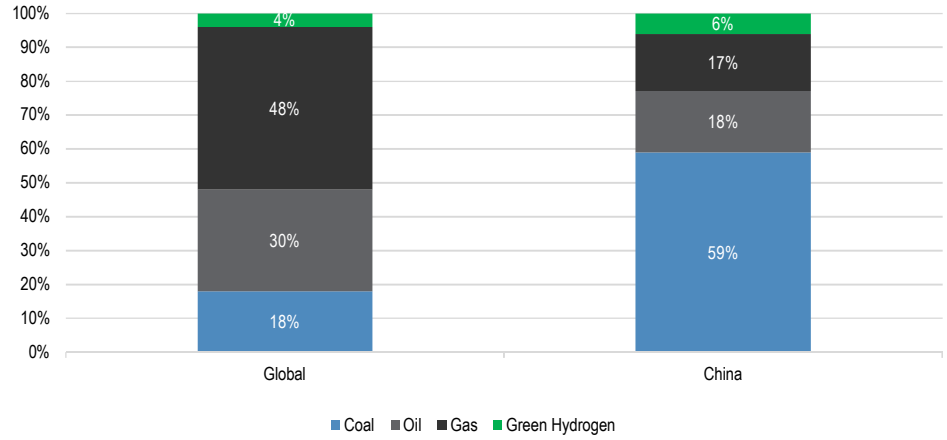
After more than tripling since 1975, demand for hydrogen among industrial users continues to rise globally but remains mostly supplied from fossil fuels, per the IEA. However, focus continues on de-carbonizing emissions-producing hydrogen (e.g., blue and grey) and developing renewable (green) hydrogen. At this point, green hydrogen only represents ~4% of total production globally (see below). While most hydrogen is currently produced through natural gas reforming and coal gasification (creating intense CO_2 emissions), companies are working to ramp low carbon production by pairing technology with CCS and using water electrolysis. This is especially important as demand for blue hydrogen (made with natural gas through steam methane reforming) grows, as a major downside to production is the CO_2 emissions created. For this reason, we think CCS could serve as a catalyst for blue growth by creating a low-carbon infrastructure for production. As more projects become approved, the unlocked spending could represent a (somewhat) significant opening for OFS companies; Rystad estimates that the value of this opportunity could be ~$400mm by 2035, with green hydrogen projects (made using water electrolysis) alone commanding 63 GW in capacity. Prospects for service companies encompass the full value chain and include MMO, transportation and infrastructure, rigs, and engineering.

Figure 59: Low-Carbon Hydrogen Production (Mt/y)



Source: IEA.

Figure 60: Green Hydrogen as a % of Global Production



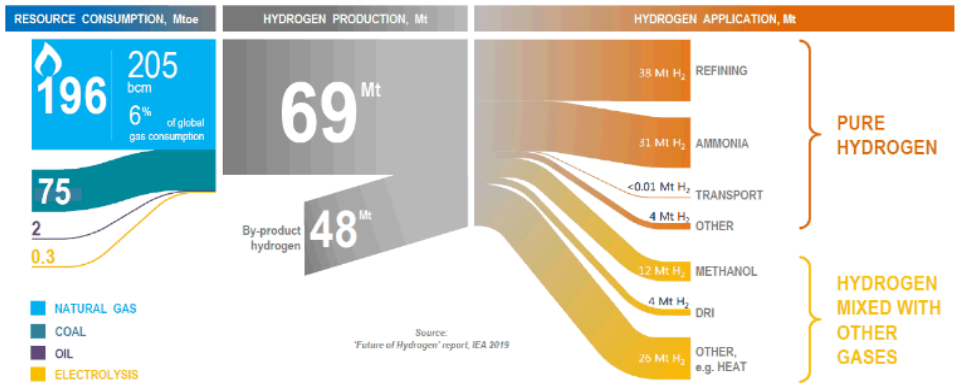
Source: IEA.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Global initiatives indicate focus on renewable hydrogen

The majority of large and currently operational projects reside in Europe; for example, the 10 GW NorthH2 project, led by Shell, is one of the largest electrolyzer developments and planned to be powered by offshore wind. Future green hydrogen projects today are mostly concentrated in Europe and Australia. The EU's hydrogen strategy calls for one million tons of green hydrogen to be produced by 6 GWS of electrolyzers by 2024, followed by 10mm tons from 40 GWs by 2030. While the plan is to develop mainly renewable green hydrogen, it also addresses the need to use other forms low carbon hydrogen until green can be brought up to scale. In Australia, the Clean Energy Finance Corporation has committed ~$200mm to green hydrogen projects with ~30 GW in capacity planned. In Asia, Japan and Korea are leading the charge by exploring importing and developing international supply chains around hydrogen.

Figure 61: Global Hydrogen Demand by Sector



Source: IEA's Future of Hydrogen report, 2019.

Table 7: Share of Electricity and H_2 in Final Energy Consumption Globally

	Transport		Industry		Buildings	
	2019	2050	2019	2050	2019	2050
Coal	0%	0%	30%	3%	4%	0%
Gas	2%	9%	21%	1%	23%	0%
Oil	95%	25%	10%	1%	11%	0%
Bioenergy	2%	3%	7%	7%	24%	31%
Electricity	1%	34%	28%	63%	32%	53%
Hydrogen	**0%**	**29%**	**0%**	**21%**	**6%**	**9%**
Other	0%	0%	5%	5%	0%	7%

Source: Bloomberg Finance L.P., J.P. Morgan Alternative Energy Research.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 8: H_2 Technologies Explained

	Production Method	Carbon credentials	Pros	Cons
Green	Hydrogen from electolysis of water using 100% renewable electricity. H2O → 2H2 + O2 285 KJ/mol H2	Zero direct CO2 emissions in production process but overal LCE of 1-5 tons CO2 per ton of H2	Ultral low CO2 emissions; offers an integrated approach to renewable electricity generation and storage. Costs expected to fall to ~USD 1kg over time. No requirement for fossil fuels, politically favoured	Currently costly ~USD 3-5/ Kg. Ineffecient vs direct electrification. Would required huge amounts of cheap renewable electricity and also uses a lot of water. Significant storage infrastructure likely to be required
Grey	Hydrogen from methane usually from natural gas via steam or auto thermal reformation with CO2 as a by-product (currently the main manufacturing route). CH4+2H20 → 4H2 +CO2 27KJ/mol H2	Direct CO2 emissions ~9tons CO2/ H2. Overal LCE ~10-17tons CO2/ ton of H2	Existing technology well used and offers cheap hydrogen at ~2-3x cost of input natural gas	Huge amounts of CO2 produced and extremely environmentally unfriendly. Also requires access to fossile fuels. Costs likley to increase as cabon taxes become higher/ more widely prevelant
Blue	Uses methane in the same processes as for Grey hydrogen but uses Cabon Capture and Sequestration to (CCS) to dramatically reduce CO2 emissions	Direct emissions ~ 1 ton Co2/ H2.Overal LCE ~ 3-6 tons of CO2/ton of H2 due to CCS	Offers 70-90% reduction in CO2 emisions. Reasonably cheap depending on assumed carbon capture cost. Uses existing infrastructure	Still leaves material CO2 emissions. Political resistance to CCS in a number of areas and cost of CCS could be relatively high.
Turquoise	H2 is produced by direct splitting of methane using pyrolysis to yield H2 and solid carbon black.CH4 → 2H2 + C 37KJ/mol H2	Production process produces zero CO2 but overall LCE of ~2-9tons CO2 per ton of H2	In theory zero process emissions and in theory cheap H2 ~ USD 1-2kg. Can use existing gas infrastructure	Still from fossil fuels so political resistance as methane leakage from upstream and gas transport can push up carbon emissions. Still an unfounded technology at scale and requirement to dispose of significant carbon black

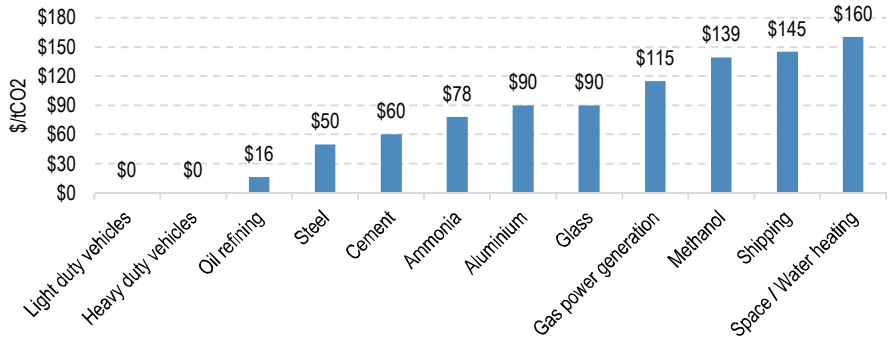
Source: Hydrogen Council, J.P. Morgan Metals & Mining Research.

Sliding down the hydrogen cost curve likely requires government support

The current cost of green hydrogen makes it a non-starter for industrial deployment but the path towards viability primarily driven by scale is logical enough to us. In the next 10 years the cost of green hydrogen (powered by European offshore wind, for example), could decrease ~60% driven by: (1) scale in production, learning rate and technological improvements as system sizes increase, (2) small efficiency gains, (3) O&M costs (with upside potential for cheaper storage) and (4) improvements in levelized cost of energy (LCOE) for renewables. If costs approach the more optimistic cases by 2050, adoption may still need to be incentivized by carbon taxes.

For hydrogen to compete as a power source in the industries seen in the below figure, carbon taxes would need to be implemented (many at eye-watering levels), except for light and heavy duty vehicles. Our Alternative Energy colleagues think green hydrogen can reach price-parity with diesel in the next 5-10 years on an energy/$ basis. BNEF estimates hydrogen (unsurprisingly) has the largest range on a cost of fuel/energy value basis but notably the lower end of the range ($5/GJ) can potentially compete with the current energy mix. **While our views are not sufficiently nuanced yet, we see an opportunity for technological innovation to create new demand.**

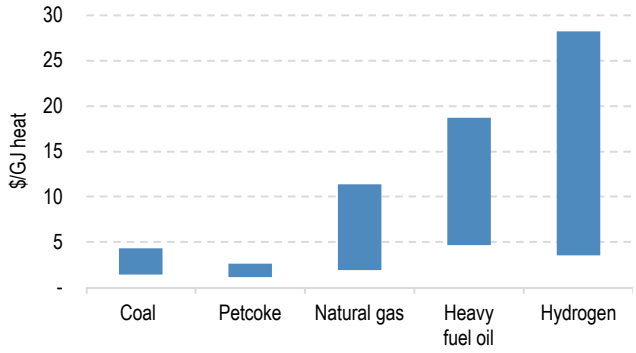
Figure 62: Carbon Prices Required for Hydrogen ($1/kg in 2050) to Compete with Each Use Case



Source: BNEF. Note: Based on a hydrogen price of $1/kg and equipment costs that vary by sector.

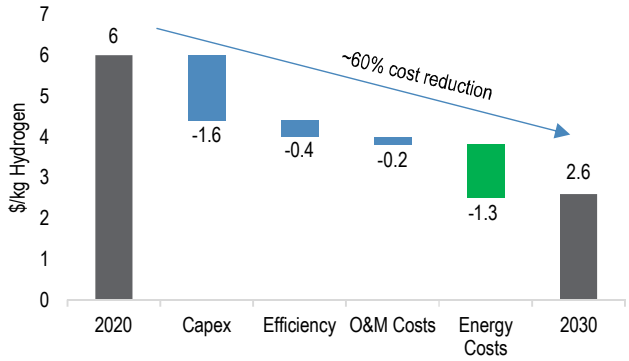
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 63: Cost of Fuel Range Based on Energy Value



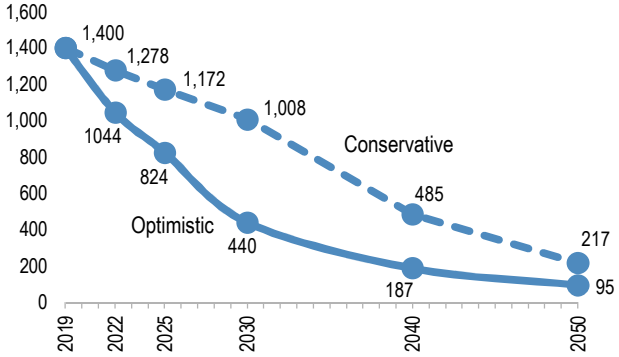
Source: BNEF.

Figure 64: Cost Reduction Levers for Electrolysis for European Offshore Wind



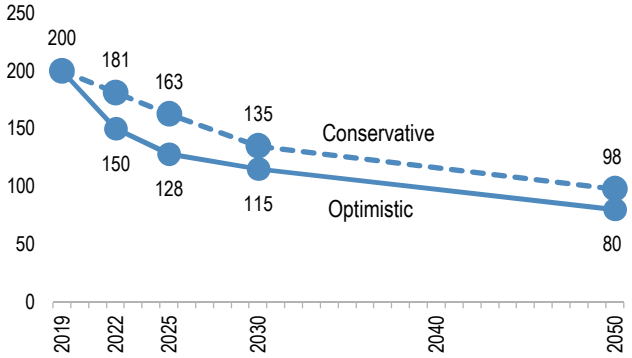
Source: Hydrogen Council, H21, McKinsey.

Figure 65: System Capex Forecast of 4MW PEM Electrolysis Projects ($/kW)



Source: BNEF.

Figure 66: System Capex Forecast of Chinese-made Alkaline Electrolysis Projects ($/kW)

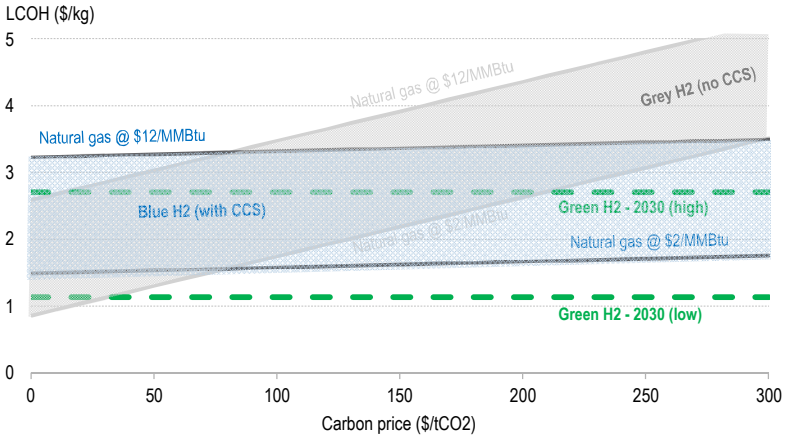


Source: BNEF.

Green hydrogen isn't the only answer, and innovation could change the curve

The two figures above show scenarios for improving economics in two of the three electrolyzer types: polymer electrolyte membrane (PEM) and Alkaline (AEL). The third avenue being solid oxide electrolyzer cells (SOEC) where SLB's joint venture with Genvia is focused. Figure 64 shows that about half of the cost improvements expected for green hydrogen are derived from the electrolyzer component.

Figure 67: Hydrogen Economics by Carbon Price

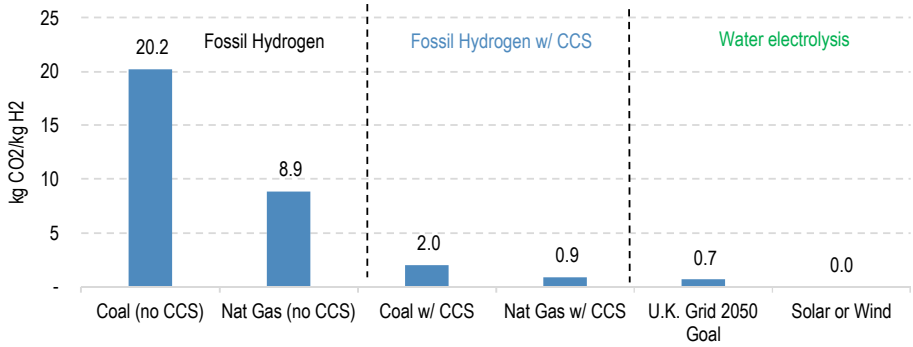


Source: BNEF.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

While grey hydrogen is the lowest cost solution in a zero carbon price regime, its emissions are by no means a long-term solution, emitting ~10x as much as blue hydrogen (see below). If natural gas prices remain at reasonably cheap levels, blue hydrogen can remain cost competitive with green hydrogen through 2030 (at least) compared to the even more optimistic cost scenarios. As carbon prices increase, economics for blue are only somewhat impaired because while the end consumption has no emissions, the unavoidable carbon footprint in the upstream remains.

Figure 68: CO2 Intensity by Hydrogen Production Type

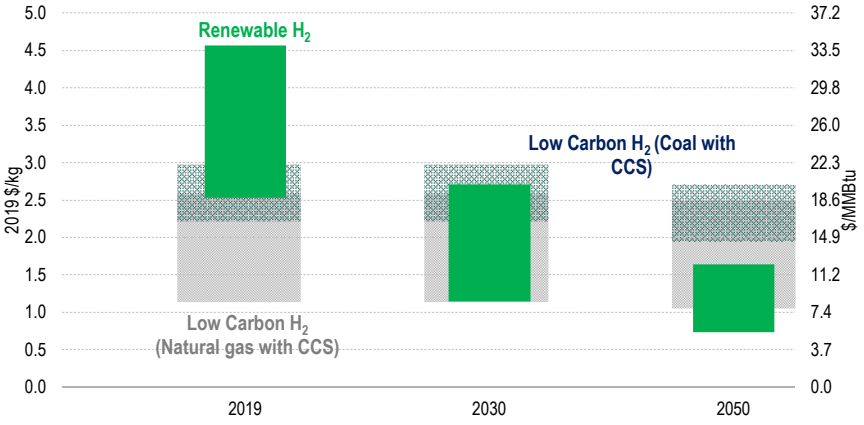


Source: IEA, BNEF. Note: CO2 intensities for hydrogen do not include CO2 emissions linked to the transmission and distribution of hydrogen to the end users. CO2 capture efficiency of CCS process assumed to be 90%.

"You're my boy, Blue": don't give up on blue hydrogen just yet

If 2020 has proven anything, it's that long-term predictions can be quickly disrupted by unexpected variables, so when looking at the industry's estimates for cost improvements by 2050, we try to think through other potential outcomes. Blue hydrogen (shown by the light grey below) currently offers comparable economics to what can be expected from green in 2030 (and notably isn't far off in 2050). Third-party forecasts call for a relatively even split between the two globally by 2050 (~40-45% for each). It could very well be the case that the path of least resistance favors blue hydrogen given its advantaged emission profile v. pure fossil fuels and proximity to green hydrogen's carbon level. As this plays out, it could screen positively for LNG-levered stocks in our coverage as the market comes to further appreciate "old" energy's transition fuel as a meaningful contributor to the evolving energy mix for decades to come (again, assuming CCS can scale with it).

Figure 69: Forecast Global Range of Levelized Cost of Hydrogen Production



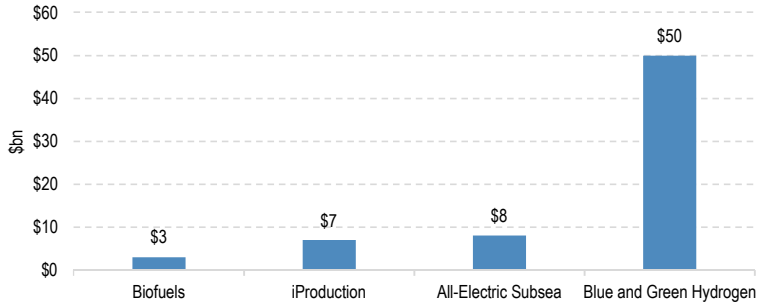
Source: BNEF.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

FTI positioned for the "hydrogen rainbow", leverage grey hydrogen leadership

Measured by installed base with a presence in over 270 plants worldwide, FTI has a market leading 35% share in grey hydrogen. We think this stronghold (along with strategic moves it's making), will give FTI the ability to pivot no matter how the hydrogen market develops. Among the hype of 2050 green hydrogen targets, grey hydrogen can be overlooked, but FTI's steam reforming technology in this industry will be needed (in addition to carbon capture) to ramp blue hydrogen. We view blue as a solid opportunity given its current emission profile and cost (compared to green) but note the usual caveats of logistical/economic obstacles need to be overcome to displace current technology. Still, FTI is hedging for the future in a smart way through its partnership with (and €15mm investment in) McPhy to accelerate its green hydrogen offerings. FTI will deploy its engineering and project management capabilities to bolster commercial viability for green hydrogen. With McPhy's recent private placement offering, it plans to develop capacity stacks for large-scale projects (>100MW) and hydrogen refueling stations (>2 tons per day).

Figure 70: FTI's Largest New Energy Opportunity through 2030 is Hydrogen



Source: Company filings.

Sizing up FTI's new energy opportunities, including Deep Purple initiative

Given the developments on hydrogen highlighted above, FTI estimates its opportunity as an EPC supplier for blue and green hydrogen represents a +$50bn opportunity through 2030. While longer-term adoption scenarios are wide-ranging, dependent on policy and technological step changes to improve the cost curve, the required buildout could be ~7x the current installed base. If green takes longer than expected to develop, FTI would benefit from its positions in blue and LNG.

The main tradeoff would be taking higher volume of blue while giving up the more valuable work with green (if FTI's investments in the market prove successful). The hydrogen exposure is largely confined to the Technip Energies business but Subsea is adapting to be a part of the energy transition. The company has been developing its Deep Purple offering for four years to use offshore to provide much needed scale to match ambitious renewable uptake forecasts. We think this solution would help with the massive infrastructure buildout and avoid the NIMBY political/social pushback, but we continue to contemplate potential permitting/legal hurdles.

The Deep Purple project looks to integrate offshore wind/wave energy with subsea power storage (e.g., hydrogen fuel cells) to power both subsea infrastructure and eventually the onshore grid. This not only builds from FTI's clear subsea expertise but also its extensive "installed base" of infrastructure which in many cases is relatively well-located to support future renewables projects. While even further away, we think the second iteration of Deep Purple could leverage the natural extension of carbon capture in offshore reservoirs. This opportunity looks to be ahead of the current market (with no $ opportunity provided by FTI), but clearly it was material enough for FTI to disclose as a medium-to-long term opportunity.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

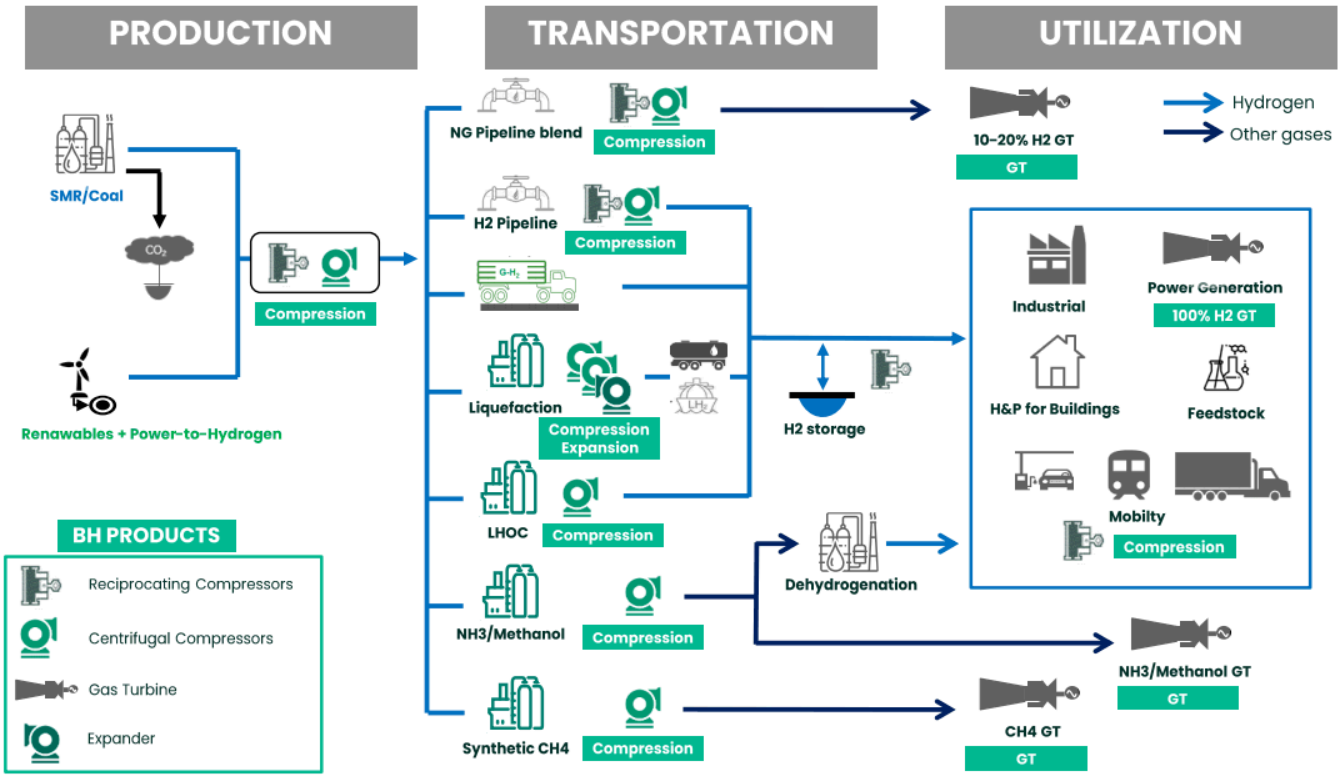
BKR is showing differentiation in hydrogen but path to materiality remains a function of tech developments and government support

Baker's TPS business offers differentiated rotating equipment and compression technology, giving it exposure to the hydrogen market irrespective of how the "hydrogen rainbow" evolves in the coming decades. BKR manufactures turbines that can be powered by gas or hydrogen, as well as compressors and expanders which are primarily required in the production, transportation and utilization phases.

BKR has sizable experience with using a variety of fuel mixtures, some with high hydrogen content, including ~70 projects worldwide using both its Frame and aeroderivative gas turbines. In one of its case studies, the NovaLT16 turbine was able to burn natural gas then switch to blends, including 100% hydrogen, importantly with no hardware modifications. Baker has worked on equipping over 70 projects worldwide with H_2-capable turbines and as the market develops we think its offering will continue to gain traction for either new projects or to enhance existing infrastructure.

The most recent data point from Baker is that construction on an ammonia site in Australia is in progress, which will use a NovaLT16 turbine on 100% hydrogen. The NovaLT12 will also be installed at Snam's gas compressor station in Italy after its successful 10% hydrogen blend test. We think BKR is a strong play on the energy transition (at least amid OFS peers), but management is rightfully conservative in noting 1) obstacles facing much-needed government intervention/support and 2) for hydrogen to scale it needs to be located near point of use given current transportation limitations resulting in loss of energy.

Figure 71: BKR's TPS Portfolio across the Hydrogen Value Chain



Source: Baker Hughes.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

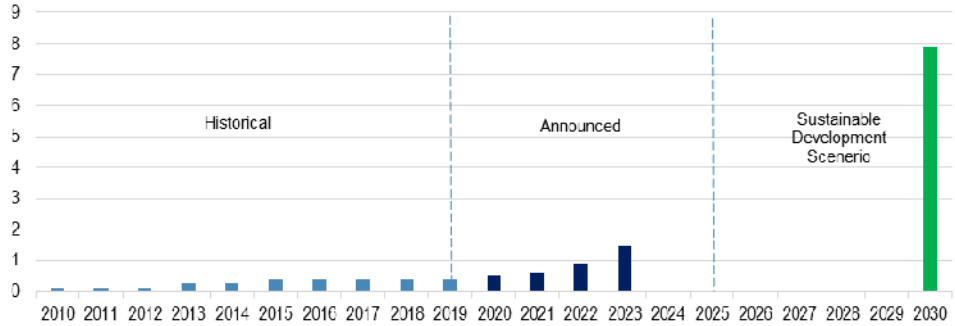
SLB investing for hydrogen success with plenty of work (and potential) ahead

Schlumberger's current exposure to hydrogen is lower than FTI and BKR (but still higher than the rest of our coverage). Earlier this year SLB announced its partnership with the French Alternative Energies and Atomic Energy Commission (CEA), as well as Vinci Construction, on a new venture tied to clean hydrogen, called **Genvia**. The objective is to accelerate industrial use of green hydrogen with SOE technology.

While electrolyzer technologies are early stages in general, SOE is still considered among the more advanced but products are not commercially viable yet. The process could offer advantages around higher conversion efficiency with the potential for producing a synthesis gas directly from steam and CO_2 which could be applied in several areas including synthetic liquid fuels. SLB is investing in this technology with that expectation to provide clean hydrogen more efficiently in a market it expects to surpass 10 megatons of volume by 2035 (comparable to the Sustainable Development Scenario below).

We highlight that while some in the industry consider electrolyzer technology to be fairly commoditized, the relatively high cost of the process is also consistently cited as a barrier to making green hydrogen economic. If SLB can develop next-gen technology on this front and lower the cost curve, its venture could capturing a large share of the enhanced economics through an IP moat.

Figure 72: Low-Carbon Hydrogen Production (Mt/y)



Source: IEA.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Digitalization of the Oilfield

As the Pandemic Accelerates Adoption, Will it Be Value Transfer or Capture for OFS?

Digital's adoption in the upstream was accelerated by 2020's events, though its impact is only beginning to blossom

The secular bear thesis for the upstream appears to have a long tail

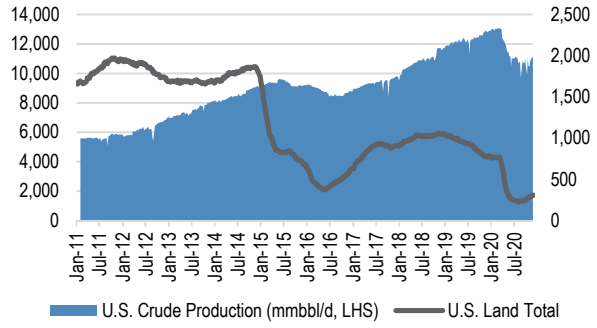
Consistent readers of our research will recall we've been highlighting digital deployment as one of the key secular levers for cost/boe deflation in the upstream for years, though much as investors have witnessed across a plethora of sectors in 2020, the global COVID-19 pandemic and rolling economic shut-downs have demonstrated the ability of OFS and E&P to deploy them at scale. Digital became the focal point of our 2019 Energy Technology Tour, less than six months before the lockdowns began, but that display was a culmination of a 5-10 year effort by the sector to bring to bear remote operations, software enabling smarter hardware, performance-based maintenance of equipment, ML/AI reinventing reservoir description and field development planning, even additive manufacturing. Emerging initiatives include migration of reservoir data to the cloud and edge computing to enable those in the field to make better decisions thanks to real-time data. The sector has come a long way from HAL's "Battle Red" initiative a half decade ago to reduce physical paperwork through digitalization. Yet not only does digital's impact seem nascent, the real battle will be over value capture between OFS, E&P and the oil price.

Is software just the cost of admission for OFS's hardware?

We consider this debate one of the key themes of the coming cycle for Oil Services as we expect relentless pressure on operators and their supply chain partners to deliver ever more efficient results. We think the empirical evidence leaves little doubt how much value has been generated for consumers of oil & gas globally by the partnership between upstream E&P and the services and equipment verticals. However, two prickly issues for OFS include: 1) in a hardware-driven sector, creating moats around software has been challenging, and 2) thus, getting paid for software solutions is challenging historically.

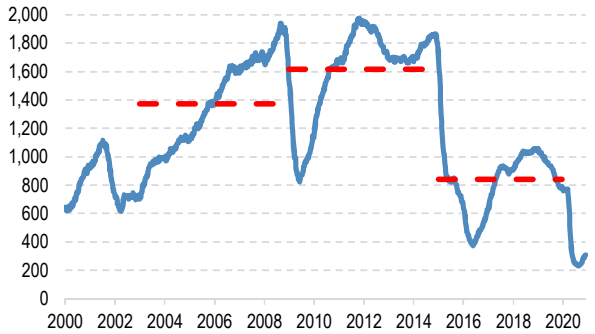
We often use land rigs as an example: to varying degrees, each of the "Big Four" is pursuing complementary strategies, with their pros and cons (mostly pros). Over the medium-long term, we suspect the best ideas will rise to the top and be disseminated, transferring much of the value to the operator and eventually the oil price. Each step-change in performance at the micro level of an individual rig improves its economic value, yet the lack of defensibility of that advantage nullifies it over time, and fewer units are needed per unit of activity. Phantom capacity creep undermines utilization and pricing power, though growth capital has at least slowed dramatically of late.

Figure 73: U.S. Crude Production (LHS) v. U.S. Land Rig Count (RHS)



Source: Baker Hughes, Bloomberg Finance L.P.

Figure 74: Total and Average U.S. Land Rig Count Cycle/Cycle



Source: Bloomberg Finance L.P.

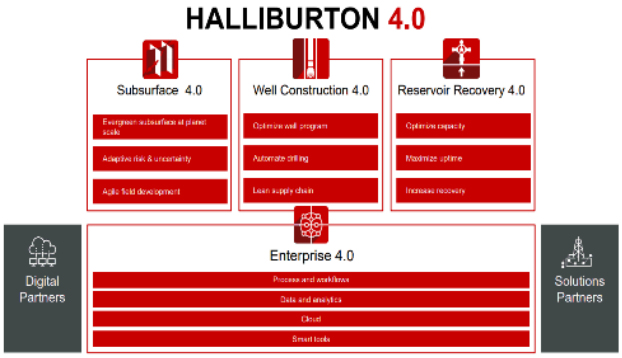
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Equipment delivering digital value, thus requiring less equipment

Similarly, equipment suppliers to both E&Ps and service companies are driving significant step-changes in productivity via digital overhauls of their products and capital items, lengthening equipment lives, extracting valuable data to inform better decision-making, reducing the impact of unplanned downtime from failures, and lowering total cost of ownership. We are seeing these initiatives bear fruit in a number of different ways, led by National Oilwell Varco (the largest OEM supplier to the upstream complex), which in its latest push forward rolled out its Max digital ecosystem to deliver clean, reliable data to its equipment users (and the means to interpret them). Field tests for Max are ongoing, with two independents and one IOC. NOV believes it can deliver +10% improvements in costs from reducing well construction costs, limiting personnel onsite and enabling automation and remote operations. Meanwhile, some service providers have chosen more vertically integrated paths (e.g., HAL) with an emphasis on lowering operating costs v. peers to sustain a margin advantage, and others (e.g., HP, NBR, PTEN) aim to upsell via automation and software-enabled enhancements.

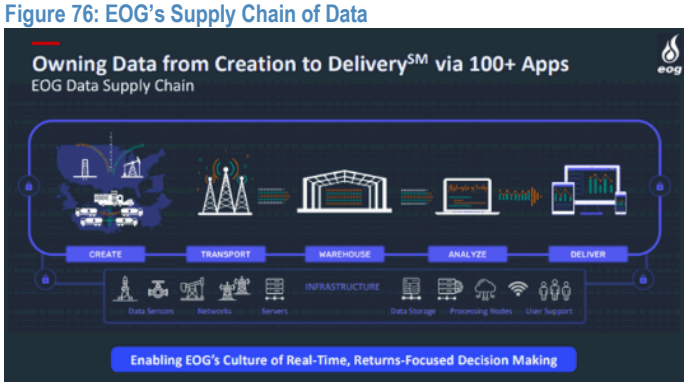
For the offshore market, RIG is using Smart Equipment Analytics (SEA), enabling crewmembers to evaluate operational, emissions and maintenance data in real time, helping to optimize uptime; the SEA suite is live on 18 of its 38 floaters. RIG is also investing to equip more of its semis with automated drilling control. Despite the stop and go offshore market given COVID-19 disruptions, RIG has impressively maintained flat efficiency y/y. In some markets (primarily Norway), RIG can be rewarded with performance bonuses.

Figure 75: Halliburton 4.0



Source: Halliburton.

Figure 76: EOG's Supply Chain of Data



Source: EOG Resources.

They say only 3% of the industry's data is used, but times are changing

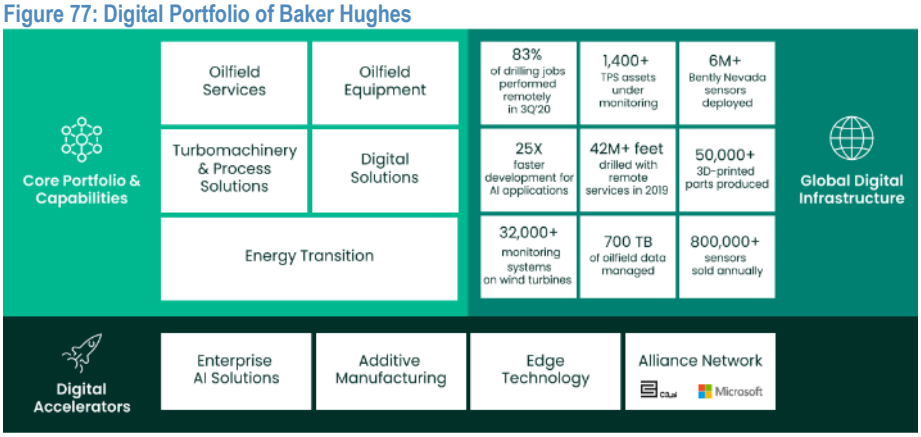
On this year's (virtual) tech tour, we heard from three leaders across the traditional oil & gas upstream value chain on how digital technology is driving the next step in efficiency gains and benefiting their cost structures.

- **HAL** offered an overview of its Halliburton 4.0 suite, a broad initiative to enable customer utilization of HAL's digital products and automation abilities, saving time and delivering superior results to the operator while also driving efficiency and reducing labor costs for Halliburton. The company also provided an in-depth look at SmartFleet, its intelligent frac system which uses subsurface sensors to create live frac visualizations that enable E&Ps to "see and control" frac stages in real-time (addressing a notable hole in maxing well performance).

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

- Next, **EOG**'s presentation revolved much around the technology the company has developed to optimize its supply chain, which has allowed EOG to tackle problems such as managing recycled frac water logistics and minimizing gas flaring. The company's ESG initiatives are facilitated by the same supply chain, making them integral to EOG's operations.
- **NOV** highlighted its Max digital ecosystem, which sets out to connect the whole oilfield and solve two important problems: 1) simplify the job of getting clean, reliable, real-time and well-connected data and 2) give NOV and its customers the ability to use larger portions of the massive amount of data generated. Together, we think such efforts present meaningful opportunities for the industry to increase both the productivity of wells drilled and the efficiency with which they are constructed, lowering the internal costs for service providers as well. However, as we've highlighted for years, the lack of an economic moat for most of the upstream supply chain makes monetization a bit more perilous, even for industry leaders.
- **BKR** also continues to drive digital adoption in all of its segments, as well as new energy. Over 80% of drilling operations last quarter were completed remotely and these types of developments help Baker to minimize its footprint onsite. BKR is focused on structuring commercial agreements to capture its fair economic share of efficiencies but the jury is still out for all of OFS in our view. By leveraging Microsoft (Azure) and C3.ai, BKR expects to benefit internally with optimized inventory, demand planning and drilling plans (reducing non-productive time). On the customer front, the full BHC3 AI Suite has been deployed with a Major operator and a Canadian oil company is using its Production Optimization package. The technology is also being utilized further down the supply chain with a national chemical company implementing BHC3 Reliability to drive efficiencies at its ethylene plant.

Figure 77: Digital Portfolio of Baker Hughes



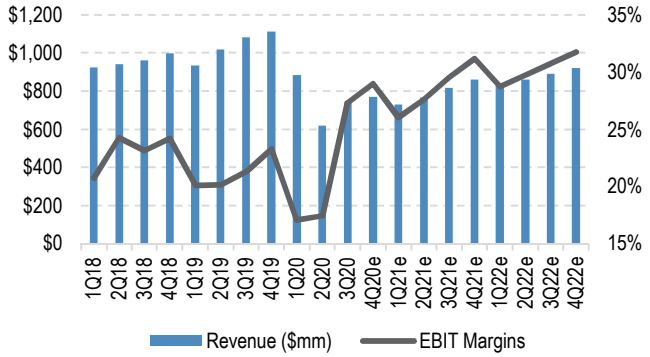
Source: Company reports.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

SLB's Digital Platform Looks to Be Another Animal, Can it Sustain Value Capture?

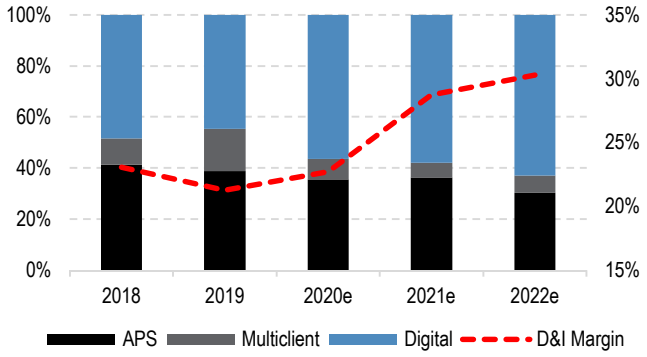
Schlumberger believes digital capabilities will be the driving force behind the next step-change in performance across the entire E&P value chain. By utilizing its deep pool of domain knowledge, and partnering with leading technological innovators, SLB aims to be at the forefront of the digital oilfield. We think the reality of a lower for longer upstream requires differentiated solutions to deliver lower cost/boe, and this is a key reason why digital leadership has become a cornerstone of SLB's roadmap to the future. SLB was targeting a doubling the contribution of its digital mix over five years pre-pandemic, and the creation of a Digital & Integration segment is providing some much-needed transparency on the scope of digital's contribution. If the combination of machine learning and artificial intelligence is as potent as SLB suggests, we see risk to dilution of SLB's core services offerings on a through-cycle basis. Still, we see SLB as uniquely positioned to create a sticky platform tied to cloud-based analysis of the reservoir.

Figure 78: Digital & Integration Revenue v. EBIT Margins



Source: Company filings, J.P. Morgan estimates.

Figure 79: Digital & Integration Mix (LHS) and EBIT Margins (RHS)



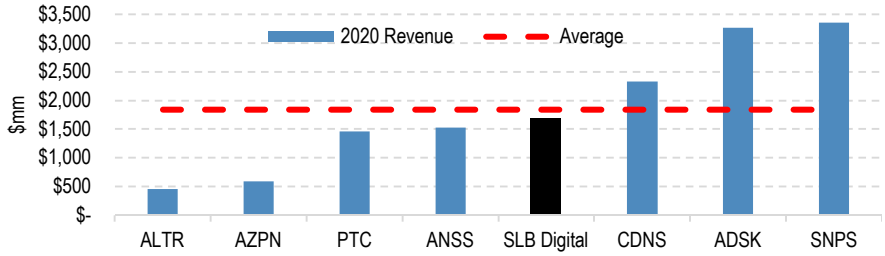
Source: Company filings, J.P. Morgan estimates.

Can DELFI become a monopolistic platform for cloud-based reservoir analysis?

Some software providers have been able to scale critical offerings to a point where their market penetration tips towards a near monopolistic structure in which switching costs become exorbitant, allowing for sustainable pricing power (think MSFT's Windows or ADBE's Acrobat). While a *much* smaller TAM than what's available to either of those, we continue to ponder SLB's potential to convert DELFI into a dominant platform that not only garners pricing power, but becomes a fly trap for other highly accretive digital solutions and maybe even incremental hardware demand. SLB is emphasizing a multitude of new revenue opportunities spawning from its digital initiatives: not just platform fees (cut across all aspects of the upstream), but cloud computing, digital edge, advanced analytics, data management, customer-driven apps, etc. The list is long, but we struggle to apply a framework to impute these assumptions into our normalized earnings model. As a result, we're looking forward to learning more from the company on these initiatives.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 80: Design Software Revenue Comparisons to SLB's Digital



Source: Bloomberg Finance L.P., J.P. Morgan estimates.

Table 9: Design Software Comps

Company	Ticker	2021 Revenue ($mm)	Revenue Y/Y	2020 Gross Margins	2020 EBIT Margins	EV/2021 Sales
Altair	ALTR	$485	8%	73%	7%	9.2x
Ansys	ANSS	1,753	8%	90%	41%	16.4x
Aspen Technology	AZPN	$727	12%	91%	54%	13.0x
Autodesk	ADSK	4,260	13%	92%	29%	14.3x
Cadence Design Systems	CDNS	$2,837	7%	90%	34%	11.7x
PTC	PTC	1,608	8%	80%	28%	8.5x
Synopsys	SNPS	$4,048	7%	81%	28%	8.6x
Average		**$2,245**	**9%**	**85%**	**32%**	**11.7x**
SLB Digital & Integration		3,139	4%		23%	
SLB Digital		$1,806	10%			

Source: Bloomberg Finance L.P., J.P. Morgan estimates.

DELFI Background: SLB first announced its next-generation digital ambitions in 2017 with the unveiling of the DELFI platform, which is now fully commercial with over 100 customers currently using some function of the DEFLI ecosystem. The praise given to SLB's digital platform from global E&P and technology partners at the company's Global SIS forum was a clear vote of early confidence for the digital initiatives. SLB's agreement with IBM and Red Hat to allow DELFI to be private, multi-cloud or hybrid is key for continued adoption across the ranging types of operators (e.g. NOCs may have concerns regarding open data platforms). Perhaps the most significant endorsement came via Woodside Petroleum's adoption of the DELFI platform at an enterprise-wide level (which the company opted to accelerate to enable remote work during the pandemic). This comes after the company was able to exceed its goal of reducing its exploration modeling time (from 18 months to 8 days) using the computing power of DELFI. Currently there are five cloud-native apps on the DELFI platform: DrillPlan, DrillOps, FDPlan, ProdOps and ExplorePlan. In addition to the SLB apps, the DELFI platform will also provide 3rd parties (including both operators and software developers) with the computing horsepower to create their own applications (using DELFI as a subscription). After completing a pilot which exhibited strong efficiencies (e.g. 200 simulations in a fraction of the time, planning wells ~8x faster), OMV was the most recent operator to partner with SLB to implement enterprise-wide deployment of DELFI with a five-year agreement. Last quarter SLB was awarded a 5-year, $109mm contract with KOC to implement digital solutions (which included Petrel), Suncor inked a multiyear agreement to use DELFI and DrillPlan is being deployed by XOM for its unconventional operations and in Saudi Arabia. Angola's National Petroleum Agency recently called on SLB to aid in its digital transformation using DELFI with the project mirroring consulting work.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

GAIA platform aims to become "the Netflix of exploration"

The WesternGeco GAIA digital subsurface platform aims to speed up the hydrocarbon discovery process by bringing all necessary exploration data to the user's fingertips, on demand in real time. Powered by the DELFI E&P digital environment, GAIA provides a personalized experience, allowing users to discover, visualize, and interact with all available subsurface data on demand, without compromising resolution or scale. GAIA offers broad appeal to a swath of customer bases: operators can manage exploration portfolios, regulators can showcase their countries' assets and industry data providers can provide client with subscription-based access to their data library. On the last point, SLB has a collaborative agreement in place with IHS Markit to provide GAIA users with IHS data access. SLB introduced the subscription-based GAIA Xchange earlier this year, which is the world's first E&P data marketplace. In 1Q20, SLB announced the Egypt Upstream Gateway in collaboration with the Egyptian Ministry of Petroleum, leveraging GAIA to digitize the country's reserves.

Figure 81: GAIA Earth Workflow

Source: Company reports.

Sensia Production Automation: where digital meets iron: the edge

Schlumberger believes an enormous digital opportunity exists in the oil and gas industry near the well, at the edge. Through its JV with Rockwell Automation, Sensia, SLB aims to attack the estimated ~$5bn addressable market for digital oilfields by combining the company's deep oil and gas domain knowledge with ROK's leading automation solutions. The JV not only offers enhanced earnings potential but also learnings SLB can deploy across the rest of its portfolio. Just as automation has increased efficiency in other process-oriented sectors, SLB expects Sensia to optimize the "manufacturing" mindset of oil and gas development. To do this, Sensia plans to offer a SaaS solution to a highly fragmented upstream market that still relies heavily on manual processes.

Figure 82: Sensia Domain Expertise/ Maturity

	Measurement	Artificial Lift	Process Automation	Data Management	Applications
ROK	◐	◐	●	●	◐
SLB	●	◐	◔	◐	●
SENSIA	●	●	●	●	●

Source: Company reports.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

ESG: Drumbeat Only Getting Louder

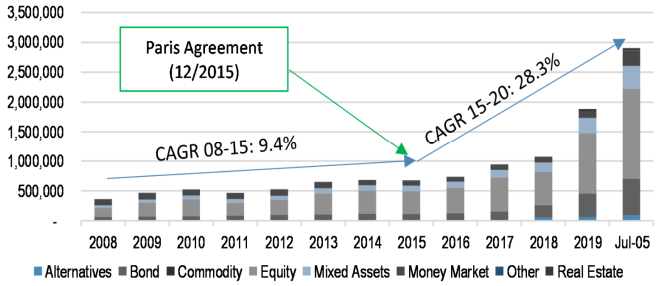
Services Increasingly on Wrong Side of "E" Dividing Line

Fossil fuel divestment commitments are on the rise, though we argue this decision has been made much easier by the relative performance between technology and energy over the past half-decade

OFS emissions manageable, but fossil fuel association a gating item for some

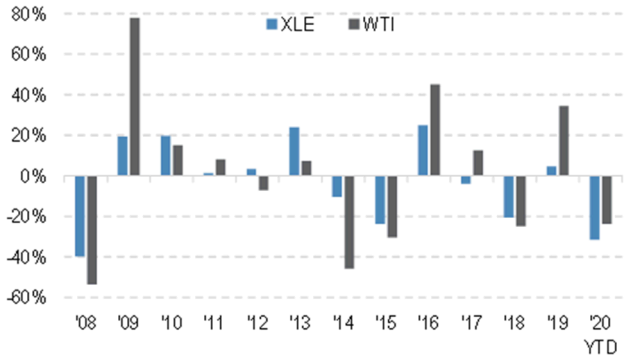
Investing frameworks driven by environmental, social and governmental principles (i.e. ESG investing) have steadily gained mindshare and AUM among institutional investors and their clients (an observation unlikely to surprise anyone reading this report). Over the last few years, not only have ESG-driven strategies gained share, but the number of institutional investors that have made commitments to divest their portfolios of fossil fuels has accelerated (ironically, those declarations have been delivered via devices, servers and infrastructure that could not exist without the use of carbon-based products). We don't see these headwinds to the OFS sector abating anytime soon, despite a meaningfully lower carbon footprint compared to E&P customers; increasingly association with fossil fuels is enough (though as we argue below, relative sector performance has made these choices easier in recent years). This report gives short shrift to the 'S' and 'G' portions of ESG strategy for the sector, as we plan a more thorough deep dive into ESG in 2021.

Figure 83:Paris Agreement a Tipping Point for ESG Investing



Source: J.P. Morgan ESG Research, company reports.

Figure 84: XLE v. WTI Performance, Indexed to 100

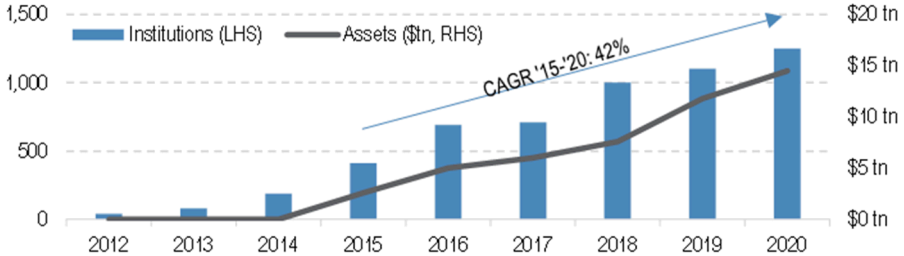


Source: Bloomberg Finance L.P.

No good deed goes unpunished: OFS stepping up reporting, transparency

We've seen meaningful reaction by our coverage, led by the large cap diversifieds and OEMS, though several small caps are also quite progressive in their approach to reducing the carbon footprints of their operations and those of their customers. Disclosures are also on the rise, via sustainability reports and additional disclosures in filings and investor decks. We highlight many of these efforts in this report. As we laid out earlier in this report, a pivot to new energy channels also holds promise (for some), but the path to market recognition is a long one in our view.

Figure 85: Divestment Commitments Have Grown Steadily Since 2015



Source: J.P. Morgan ESG Research based on gofossilfree.org.

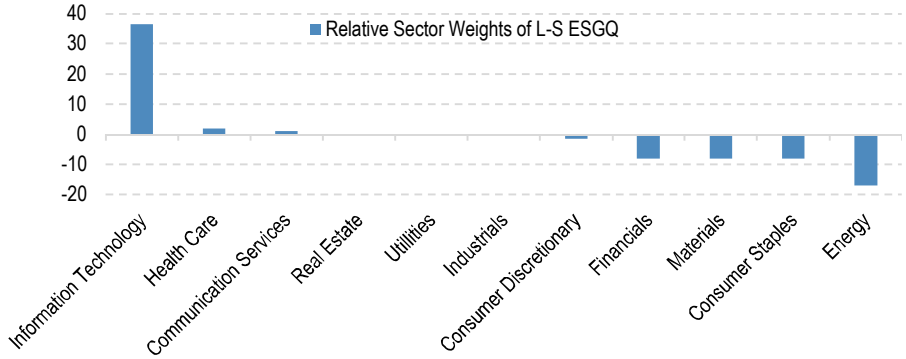
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

We believe poor energy fundamentals have been at least as big a driver of ESG flows and divestment commitments than government resolutions to address climate change

Correlation v. causation of 2015-2020 ESG performance still difficult to parse

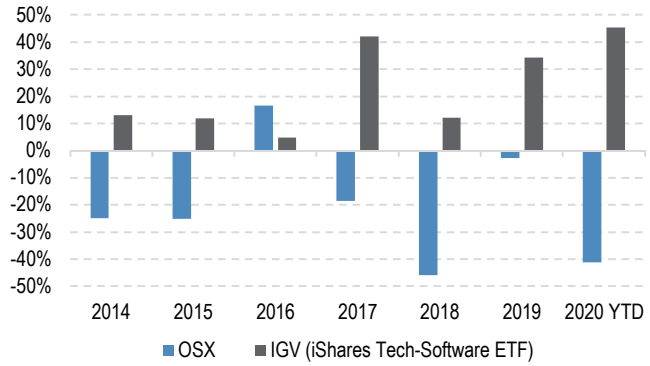
ESG assets under management have been among the few actively-managed strategies to swell in the back half of the 10's, while passive strategies were generally taking share from traditional active ones. Our ESG colleagues point to the Paris Accord (adopted in 2015) as the 'tipping point' in ESG's acceleration of inflows. We won't dispute the Paris Agreement has played a key role in the shifting perception of investors towards the relative importance of addressing climate change, but we emphasize that these decisions have been made much easier by the relative performance of energy v. technology over the same timeframe.

Figure 86: Sector Tilts Towards Tech & Away from Energy Have Helped ESG Performance



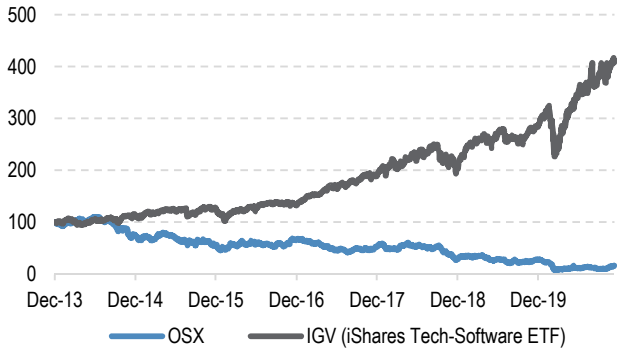
Source: J.P. Morgan Quantitative and Derivatives strategies, MSCI, I/B/E/S (Page 5 - full report here).

Figure 87:Oil Services v. Software Equity Performance, '14-'20 YTD



Source: Bloomberg Finance L.P.

Figure 88: OSX v. IGV Performance Since 2014, Indexed to 100



Source: Bloomberg Finance L.P.

Addressing the key levers to attack the 'E' challenges in Oil Services

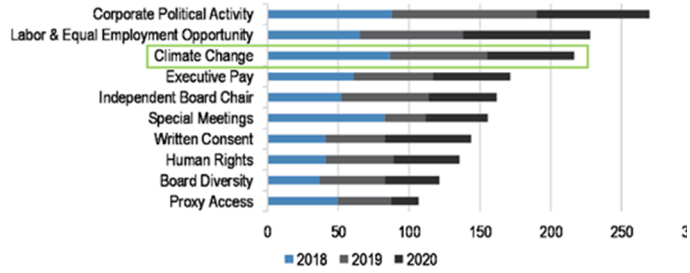
The sector has three primary means of creating positive rate of change on emissions: 1) lowering its own carbon footprint via new processes or technology, 2) lowering the carbon footprint of its customer base (which by definition has a much larger footprint), and 3) developing and scaling technology in renewable energy channels. With new energy opportunities addressed in another section of this report, we highlight some of the recent wins and future opportunities for the sector in the first two buckets here. **Whether the emission impacts are internal or external, the mandate is clear: the initiative needs to not only have a positive environmental impact, it must also deliver superior economics as well.**

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Key Lever 1: Lowering One's Own Carbon Footprint

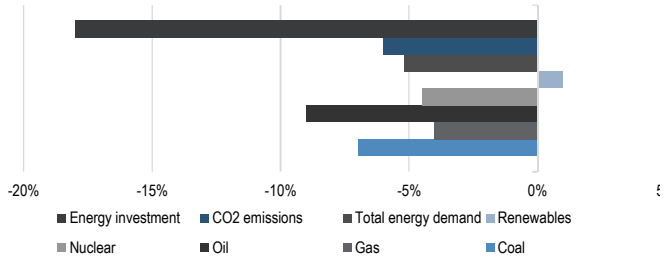
While the investor spotlight has traditionally been placed more firmly on producers, the acceleration of the energy transition has forced our coverage to address how it will adapt to the change. Still associated with fossil fuel production, reducing the carbon footprint of related activities is an important part of ESG-driven strategies for OFS. Per the GHG Protocol corporate standard, Scopes 1 and 2 encompass those emissions which are company-owned; Scope 1 emissions are emitted directly from company operations and Scope 2 result from the consumption of energy by the company. Our large caps have taken a leadership position in establishing emission reductions targets (which we will discuss shortly in this report), and other players within our coverage have also initiated efforts to curb these (see below).

Figure 89: Climate Change represented the 3rd most common ESG issues for shareholder proposals



Source: J.P. Morgan EU Oils Research, based on U.S. SIF Trends Report

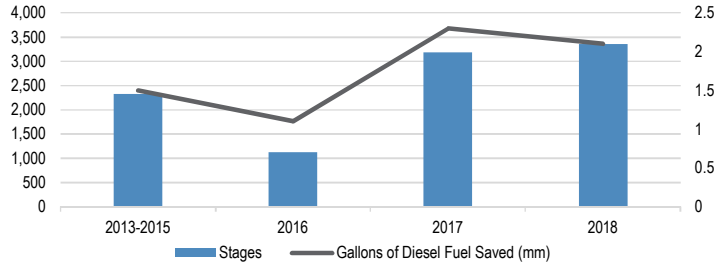
Figure 90: 2020 Estimated Y/Y Change in Energy Demand and CO2 Emissions



Source: IEA World Energy Outlook 2020

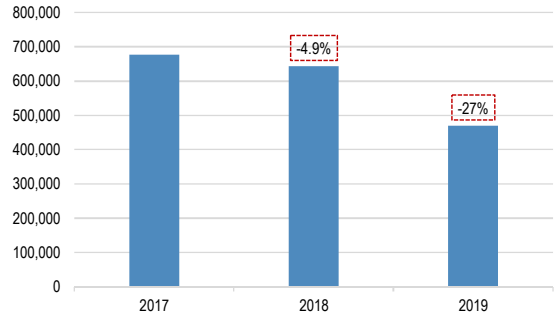
MRC has implemented low-E valves to control fugitive emissions, which leak from equipment during hydrocarbon production processes; the low-E valve will not release fugitive emissions greater than 100 PPM, per management. On a similar note, PUMP, NEX, and PTEN have all implemented dual-fuel engines, requiring less diesel fuel and in turn reducing the CO2 emissions of their operations. There are also opportunities for OFS to reduce the scale of its own operations; for example, WTTR has stated its intent to significantly lessen trucking requirements and increase water conservation with automation through its WaterOne platform. Importantly, we think OFS and producers can align their priorities to better achieve their climate goals. NESR has begun working both internally and with its partners in the Middle East to limit water usage and emissions. RIG equipped the Transocean Spitsbergen with the world's first hybrid energy storage system, allowing for 14% reductions in fuel use. The investment was partially funded through contract-based fuel saving incentives with Equinor and by the Norwegian NOx Fund, a prime example of OFS and operator priorities being in sync.

Figure 91: Patterson-UTI Estimated Diesel Fuel Reduction from Dual-Fuel Engine Use



Source: Company Presentation

Figure 92: FTI Scope 1 and 2 GHG Emissions Reductions



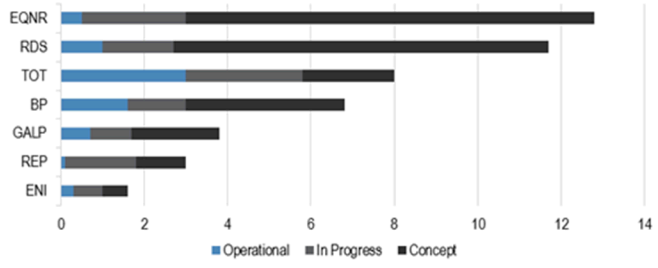
Source: Company Presentation

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Key Lever 2: Lowering Operators' Carbon Footprint

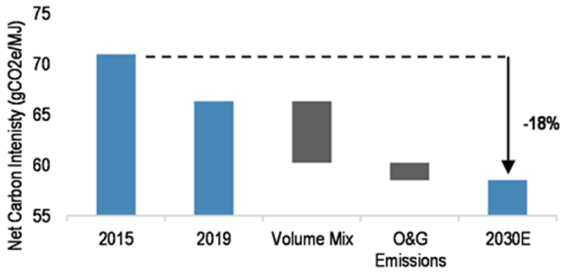
2020 saw a spectrum of goals made across industry leaders globally, led by BP which has committed to cut upstream production by 40%, invest $5bn annually in low carbon technologies, and achieve 50 GW in renewables capacity by 2025 (see below). Across our coverage's customer base, IOCs have led the charge but NAM producers have begun to follow suit. OXY is the lone U.S. producer to commit to achieving net-zero emissions by 2050, while PXD, XOM, and CVX have each committed to formal reductions by 2030. As customers increasingly focus on being greener and enhancing their renewables capabilities, opportunities have opened for OFS companies to help enable them to achieve these emissions goals. In addition to digital and software offerings, other service providers are looking to bring products to market which allow customers to reduce the scale of operations (and in turn the impact of activities on the environment). NINE's new dissolvable plug eliminates the need for coiled tubing to drill-out plugs, reducing the scale of operator's activities (and thus emissions). WHD's SafeDrill provides both safety and time advantages by requiring workers to make fewer trips into confined spaces during the drilling process, while also eliminating BOP manipulation and "hot work" to cut casing. As a result, the environmental impact of the E&P's activities is lower.

Figure 93: E&P Companies' Large-Scale Renewable Capacity by Status (GW)



Source: Rystad

Figure 94: TOTAL Projected Net Carbon Footprint reduction to 2030



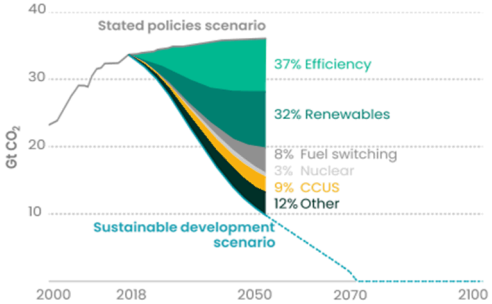
Source: J.P. Morgan EU Oils Research.

Another initiative common among our land drilling and pressure pumping coverage is the de-carbonization of equipment. The dual-fuel engines implemented by LBRT, NEX, and PTEN are further evidence of OFS and operator low carbon initiatives being aligned. By partnering with its E&P clients through its ESG Frac program, LBRT has been able to make ~50% of its total hhp low-emission, creating the largest low-emission frac fleet in the market. There has also been growing interest to electrify the entire wellsite; FTI will be first to market a fully electrified subsea system, and NOV and NEX have partnered to test NOV's Ideal eFrac fleet. Additionally, NOV has tapped into new energies to power its equipment, offering solar-powered water pumps.

Figure 95: Cactus Wellhead SafeDrill v. Conventional Wellhead

Source: Company Presentation

Figure 96: Global CO2 Emission Reductions



Source: Baker Hughes presentation, IEA

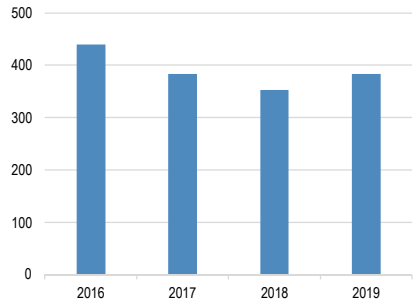
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Large Caps Establishing Leadership Positions on "E" via Emission Reduction Targets, Science-based Methods

BKR and FTI are positioning themselves as the green energy leaders in OFS

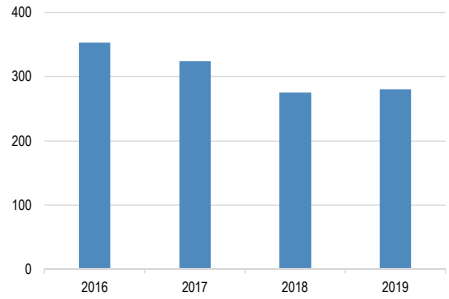
During our JPM Technology Tour, the large caps solidified their footing as leaders in OFS regarding emissions reductions by presenting their specific targets and progress made. By utilizing renewable resources (including wind, hydro, and hybrid/biofuels) for internal energy consumption, FTI intends to reduce Scope 1 and 2 emissions by 50% by 2030. While BKR established the same 2030 reduction goal, it went a step further by committing to achieve net-zero emissions by 2050 (the only OFS player to do so). In a recent update, the company reported meaningful progress by successfully reducing 2019 Scope 1 and 2 carbon equivalent emissions to 31% below its 2012 baseline. The slight reversion to emissions growth in 2019 was mostly due to an expanded reporting boundary for Scope 1 and increases in operational activity; however, BKR's initiatives to improve energy efficiencies and successfully integrate renewables globally offset a majority of the collective pickup.

Figure 97: BKR Direct Emissions (metric tons CO2)



Source: Baker Hughes

Figure 98: BKR Indirect Emissions (metric tons CO2)

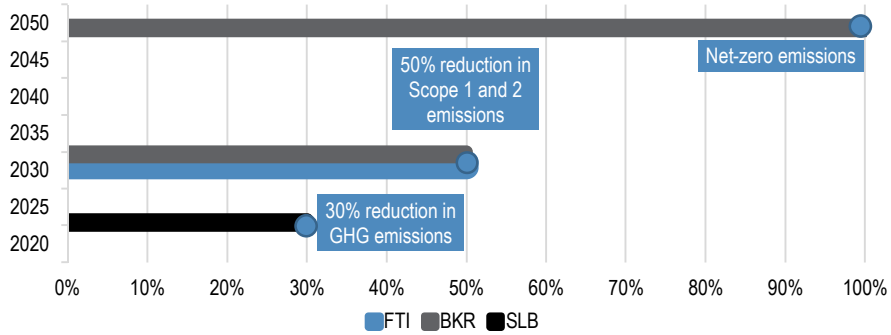


Source: Baker Hughes

Expect the rest of OFS to follow SLB's lead on emissions reporting, redressing

SLB was the first company in the O&G space to commit to science-based targets in 2019 (meeting the goal of the Paris Agreement to limit global warming to well-below 2 degrees Celsius above pre-industry levels), which will be set by the end of this year. The company's initial goal is reduce GHG emissions from fuel and power consumption by 30% by 2025. Next year, HAL is expected to follow in the footsteps of SLB and submit its own science-based targets to be approved in 2022. Additionally, while not a specific emissions-reduction goal, NOV has pledged to reduce its energy consumption by 5-10% below its established baseline value.

Figure 99: FTI, BKR, and SLB Emissions Reductions Goals



Source: Company presentations.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

The ABCs of ESG for energy stocks

In 1970 Milton Friedman argued that a company's only responsibility is to maximize shareholder value. However, investors are beginning to question if the focus should not solely be on "share" holder value, but instead on the impact on broader "stake" holders. The ESG investing approach aims to identify how well a company addresses its many stakeholders, going beyond investors, to include employees, customers, suppliers, communities, and the environment. While it's no surprise that the "E" gets an outsized level of attention within the energy complex, ESG stretches across social responsibility and corporate governance as well, and we see room for enhancement across all pillars for our coverage. While this report is primarily weighted to the "E", we intend to provide deeper dives into all three categories in the coming months.

Figure 100: Basic Environmental, Social Responsibility and Governance Investment Principles

3 Pillars	*10 Themes*	*37 ESG Key Issues*	
Environment	Climate Change	Carbon Emissions* Energy Efficiency Product Carbon Footprint	Financing Environmental Impact Climate Change Vulnerability
	Natural Resources	Water Stress* Biodiversity & Land Use	Raw Material Sourcing
	Pollution & Waste	Toxic Emissions & Waste* Packaging Material & Waste	Electronic Waste
	Environmental Opportunities	Opportunities in Clean Tech Opportunities in Green Building	Opp's in Renewable Energy
Social	Human Capital	Labour Management* Health & Safety*	Human Capital Development Supply Chain Labour Standards
	Product Liability	Product Safety & Quality Chemical Safety Financial Product Safety	Privacy & Data Security Responsible Investment Health & Demographic Risk
	Stakeholder Opposition	Controversial Sourcing	
	Social Opportunities	Access to Communications Access to Finance	Access to Health Care Opp's in Nutrition & Health
Governance	Corporate Governance*	Board** Pay**	Ownership** Accounting**
	Corporate Behaviour	Business Ethics* Anti-Competitive Practices*	Corruption & Instability Financial System Instability

Source: MSCI ESG, J.P. Morgan Quantitative and Derivatives Strategy

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Making Oil Services Investable Again

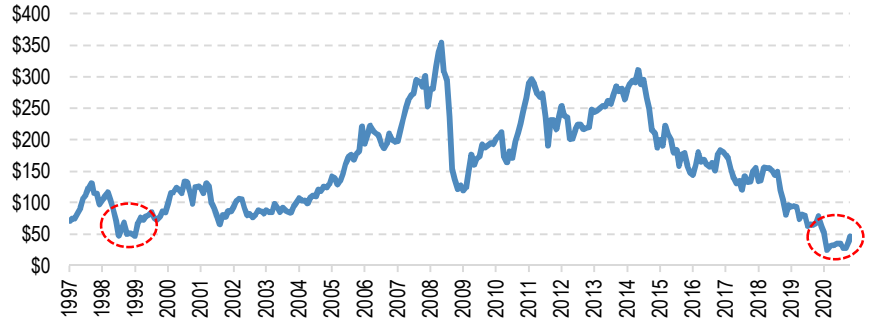
Updated Thoughts on the Path to a Positive Revision Cycle

The most common question asked on the road is, "What's it going to take to make the stocks investable?"

Of all the events wrought in 2020, one of them was closing out a "lost decade" for oil services equities, with E&P capital spending back to 2006 levels, yet global production +12% higher at the start of the year. After posting the best stock returns in energy in the first decade of the new century, OFS gave it all back (and then some) over the past 10 years, with the OSX currently near its prior lows of 1999. **While demand for the stocks is understandably muted, the most common question asked by investors is, "What's it going to take to make the stocks investable?"**

As we've written many times in these pages and others, the upstream is a victim of its own success. After successfully curing "high prices" by cracking the shale oil code beginning in 2010, all of the subsequent productivity gains and efficiency successes (i.e. secular deflation) eventually became headwinds for the sector inasmuch as the negative impact on price has more than offset volume gains, particularly for the supply chain. As a result, OFS has experienced material negative revisions to FY2 EBITDA every year since 2015 (A Watched Pot Never Boils).

Figure 101: Oil Services Stocks Have Fully Unwound Two Decades of Performance



Source: Bloomberg Finance L.P.

The pandemic appears to have pushed out *and lowered* the group's mid-cycle level of earning power out to the middle of the decade (A View to 2025) given the time required to overcome the dislocations of 2020. OFS equity performance seems to have quelled the perpetual bullishness of the sell side, leaving current FY2 and FY3 estimates achievable, no longer wishful thinking. Near-term, the road to recovery still runs through U.S. shale, though the amplitude is likely stunted by insufficient oil demand to require shale production growth. Meanwhile international markets likely begin a slower recovery into 2022/2023. Offshore is the most challenged, and we see few paths to a material increase activity until closer to the middle of the decade at the earliest. Until there is a call on long cycle barrels, the group looks more like a trading vehicle, with the focus on near-term FCF generation.

Even prior to the reset of oil demand from the pandemic, we believe **the market has assumed shale plus OPEC+ will meet medium/long-term demand growth without a material call on long cycle** (read: deepwater) barrels. Prior iterations of shale production restraints (e.g., midstream capacity limits, even investor-led capital discipline to spend within cash flow) were not satisfactory to us in shifting fundamentals for OFS (even if in practice both have been bearish) because they are largely artificial. **Therefore, until the geology turns in such a way that cost/boe of the incremental barrel reverts higher, we find it difficult to see a fundamental case for oil services investing (i.e. a multiyear positive earnings revision cycle).**

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

2020 Year in Review

A Year to Forget, But Did OFS Touch Bottom? Maybe.

March represented the group's 7th new low in seven years; even if the market doesn't return to those levels, we're not convinced the OSX won't

Table 10: 2020 OFS Price Performance

YTD		Since 10/28	
NINE	-70%	WHD	23%
OIS	-68%	NOV	38%
RIG	-64%	BKR	58%
FTI	-54%	SLB	61%
NBR	-51%	DNOW	61%
MRC	-50%	RIG	62%
WTTR	-49%	NEX	68%
PTEN	-46%	FTI	69%
HP	-45%	HP	71%
NEX	-45%	CLB	75%
NOV	-44%	WTTR	76%
SLB	-43%	OIS	76%
OII	-42%	NBR	78%
DNOW	-41%	PTEN	87%
DRQ	-30%	NINE	105%
PUMP	-28%	NESR	110%
TS	-26%	DRQ	111%
CLB	-24%	HAL	116%
HAL	-18%	LBRT	117%
WHD	-18%	OII	130%
BKR	-14%	MRC	143%
LBRT	1%	TS	169%
NESR	7%	PUMP	243%

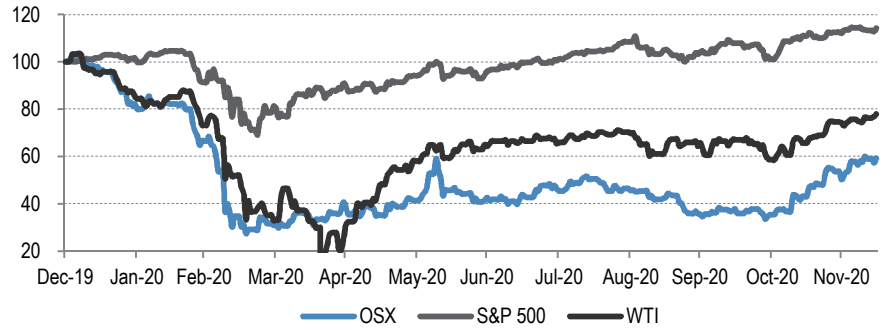
Source: Bloomberg Finance L.P.

Admittedly after 2020 there's not much market cap left to destroy

Oil services stocks have plumbed new lows for seven consecutive years, and FY2 EBITDA estimates have been revised lower by at least 20% in each of those years. While it's understandable for significant negative revisions during downturns (e.g., 2015, 2016, 2020), this phenomenon took place even during the upcycle (i.e. 2017-2019). Aside from a fluke of timing in late 2016 (as yearend coincided with an OPEC+ production cut), the sector would have lagged the market for a decade straight (instead only 9 of 10).

At the bottom in March of this year, the OSX was only 7% of its 2014 peak and, even after the furious rebound in 4Q20 (+116% since March), the index sits at levels only seen previously in 1999. If 2020 will be defined by the >70% drop in the stocks in 1Q20 (ahead of a >50% historic drop in NAM activity in 2Q), it's worth noting the group experienced six moves of more than 20% YTD (v. 4/5 in 2019/2018), with even greater amplitude (avg. 60%) due to "the law of small numbers". Did 2020 mark the secular trough for OFS stocks? We think that could be the case for some, but we doubt it's the floor for all as the full impact of secular deflationary levers in the upstream have yet to fully manifest themselves. Indeed, we had several stocks pierce their March lows in late October of this year.

Figure 102: Oil Services (OSX) Performance, YTD v. S&P 500, WTI, Indexed to 100



Source: Bloomberg Finance L.P.

Even if energy transition is slower than bulls appreciate, sentiment looks sticky

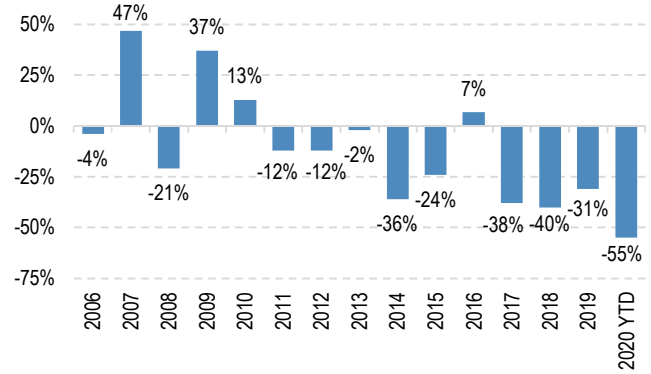
The pandemic-led collapse in oil demand and upstream activity coincided with accelerations in digital adoption across most (all?) sectors and a material shift in sentiment (among investors, the media, and broader public) towards renewable energy sources. The efficacy of the barbell of long technology, short energy has made even generalists indifferent to ESG pressures inclined to ignore energy (now only ~2% of the S&P). Though we've been chronicling this shift for years, 2020 seems to have accelerated and solidified new energy's mindshare among investors.

Consolidation cycle underway as 'dead wood cycle' shrinking capacity

A year ago in our 2020 Outlook we made the economic case for "mass consolidation" across several overpopulated service lines, as we'd long expected several players to be forced into restructuring. One silver lining of the pandemic appears to be the rationalization of excess capacity across the space, not least in pumping and other commodity NAM onshore markets. Meanwhile, nearly the entire offshore drilling complex is in restructuring (ex-RIG, DRLCO), though the impacts on market structure and rig attrition are still to be seen. **Expect more M&A in 2021.**

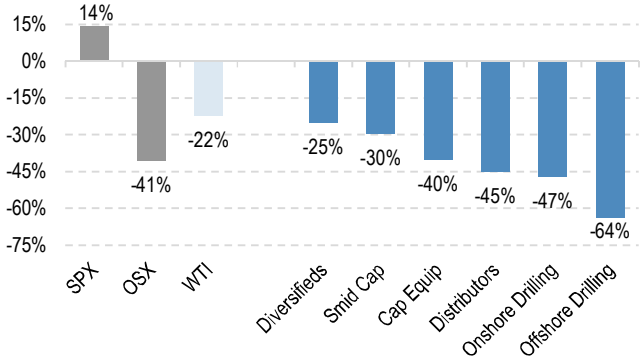
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 103: OSX Index Relative Performance v. S&P 500



Source: Bloomberg Finance L.P.

Figure 104: YTD Price Performance by Sub-Sector

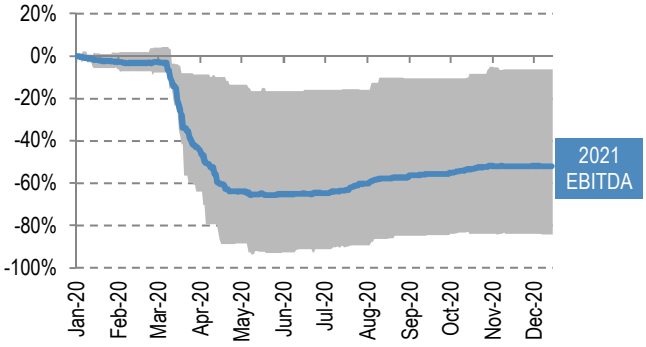


Source: Bloomberg Finance L.P.

NESR and LBRT stand out as best performers; NINE, OIS lag the most

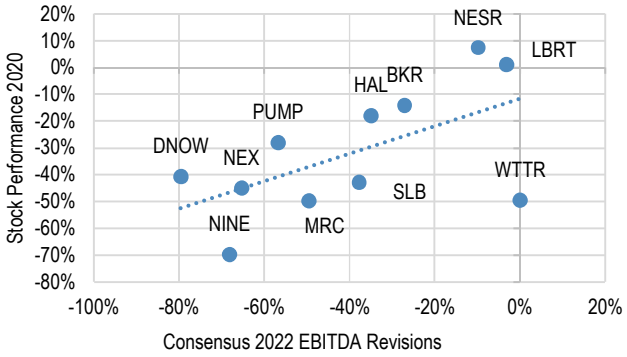
NESR posted the best 2020 performance among our coverage (+7% YTD) as it benefited from a differentiated MENA operating base. LBRT was runner up (+1% YTD), aided by a well-received deal to acquire OneStim from SLB. Meanwhile NINE stood out as the worst performer (-70% YTD), hindered by elevated leverage and full exposure to collapsing NAM demand. OIS was barely ahead (-68% YTD) as balance sheet management measures proved insufficient to offset macro headwinds.

Figure 105: 2021 Consensus Diversified and Smid-cap EBITDA, Indexed to 1Q20



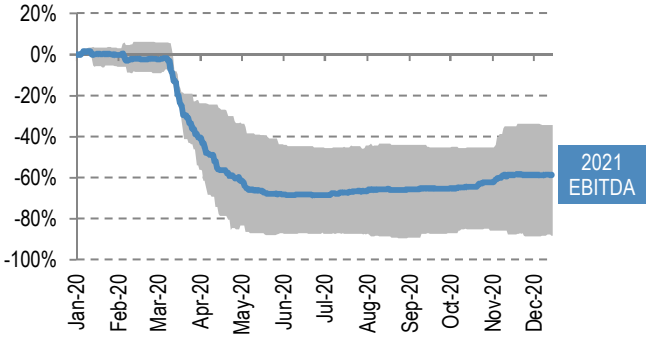
Source: Bloomberg Finance L.P.

Figure 106: Consensus Diversified and Smid-cap Performance v. 2022 EBITDA Revisions (YTD)



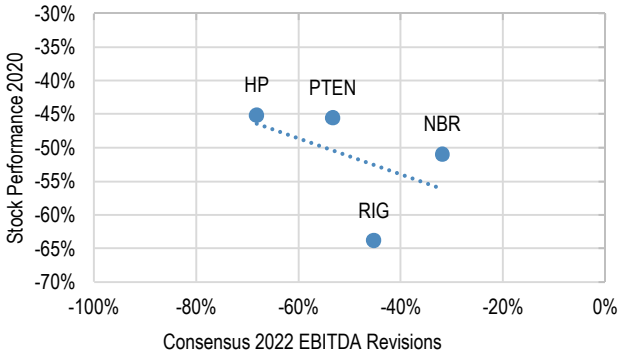
Source: Bloomberg Finance L.P.

Figure 107: 2021 Consensus Land and Offshore Driller EBITDA, Indexed to 1Q20



Source: Bloomberg Finance L.P.

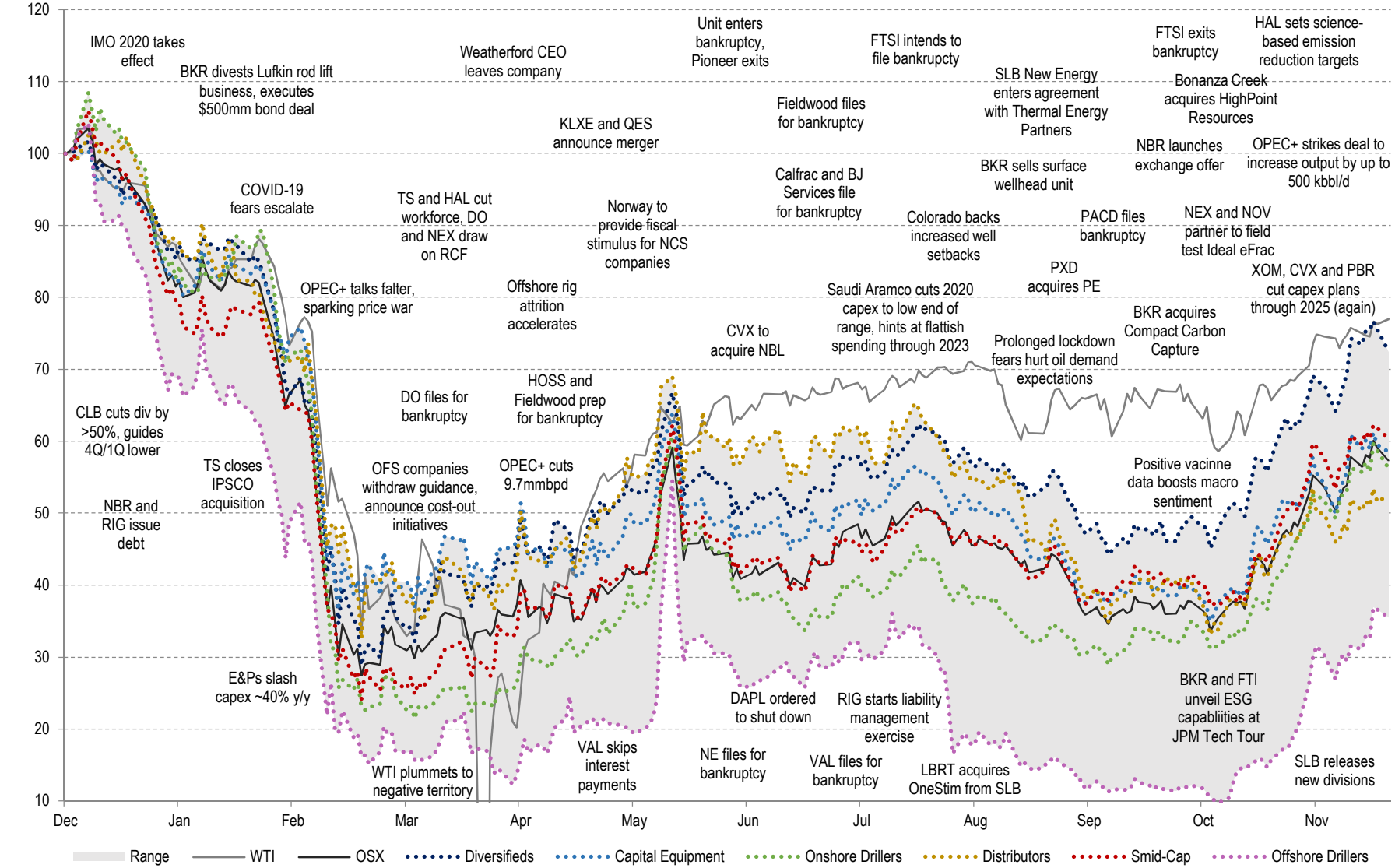
Figure 108: Land and Offshore Driller Performance v. 2022 EBITDA Revisions (YTD)



Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 109: 2020 Year in Review: OSX Index v. Comparable Returns, Indexed to December 31st, 2019



Source: Bloomberg Finance L.P., Company reports, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Oil Macro: Unresolved Fundamentals

Uncertain recovery for oil as the market remains imbalanced

After the extreme drop into negative territory in April (for WTI, anyway), oil prices have managed to stabilize in a ~$35-$45 range since June. Positive COVID-19 vaccine news has driven prices higher of late, while a resurgence of cases globally and OPEC+ uncertainty has mitigated the recovery at times. The market remains oversupplied as it awaits 1) successful COVID-19 vaccine distribution, 2) resulting demand recovery, and 3) OPEC+ agreement compliance in 2021.

Despite reassuring vaccine results, we think the oil market has a way to go before rebalancing given lingering demand risks

The implemented COVID-19 containment measures have resulted in a demand-driven market (a reversal from the previously supply dominated price dynamics that ruled since late 2014), and our Commodities Research colleagues expect it to remain this way until demand normalizes. The team sees a successful vaccine breaking the link between infections and mobility; however, the presumed distribution pattern of vaccinations will result in a wide disparity between developed markets (plus China and India) and emerging markets. Accelerating cases will likely be a drag to start 2021, with vaccine distributions improving the outlook for the remainder of the year (though imbalances across sectors and countries will persist). **With the demand recovery profile uncertain, we think 2022 is a better bogey than 2021 for potential market balance. Medium-term, we stick with our call for range-bound oil as short-cycle producers will continue to hold an advantage over long-cycle as growth returns.**

Table 11: Oil Price Risks to Monitor in 2021

	Expectation	Comment / Price Response
Balanced Risks		
Global and regional demand	Global oil demand does not recover to pre-pandemic levels until 2022, falling -3.3% y/y in 2021. The demand recovery profile and timing will differ by region, with the U.S. and Europe lagging behind Asia, where average demand in 2021 is expected to be ~3% higher than 2019 levels	The lag in demand recovery will pressure crack spreads globally, which will be tough for all refiners (especially those in the U.S. and Europe). With the addition of refinery closures and conversions which have already occured in the U.S. and Europe, Asian refiners will have more room to gain share
Non-U.S., non-OPEC+ output increases in 2021	U.S. producers are expected to keep production flat in 2021, but other non-OPEC+ producers are seeing longer-term investments come online and are expected to increase output	The non-U.S., non-Russa oil supply is projected to grow by just ~0.5 kbbl/d in 2021. This should have minimal effect if U.S. production remains flat and OPEC+ members stick to its agreement
Bearish Risks		
Iran production grows	The election of Biden and likely rollback of sanctions boosts Iranian production	A Biden administration will likely seek to add the U.S. back to global alliances and improve relations with Iran. With this, ~500 kbbl/d of exports from Iranian floating storage are projected to return by 2H21
COVID-19 resurgence	Preventative measures will still need to remain in place until enough of the population is vaccinated or herd immunity is achieved, and a slip up could result in an increase in infections	A new surge in infections would crush mobility again, keeping it linked to infection and throwing the market further into imbalance. Risks of another strand or new COVID virus are hard to quantify, but could be tail risks which slow the reopening
Bullish Risks		
COVID-19 vaccine success	5 vaccines are expected to receive regulatory approval for emergency use in 4Q20 or 1H21	The vaccination of ~14% of the world's population would likely allow mobility to return to pre-pandemic levels. However, ~60% of the population needs to receive it for social and economic life to go back to normal, and herd immunity will need to be acheived before the link between infections and mobility is eliminated
U.S. production restraint	Preliminary E&P budgets suggest relatively flat production y/y in 2021	Minimal capex spending results in restrained U.S. shale production, meaning OPEC+ will not have to battle for market share immediately
Strong OPEC+ compliance with production quotas	After tapering production cuts at the December meetings, OPEC+ members stick to the amended 2-year agreement through 2021	OPEC+ agreed to add up to 500 kbbl/d of production beginning in January, followed by monthly meetings where output can be revised in either direction by no more than 500 kbbl/d. As oil demand remains uncertain, compliance remains vital to allow prices to rise and not throw the market into further imbalance. Russian compliance seems likely given the desires to achieve higher prices and avoid another price war with Saudia Arabia

Source: J.P. Morgan.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 12: JPM Global Oil Supply and Demand Balance Summary

	2019				2020E				2021F				2022F				2019	2020E	2021F	2022F
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q				
Total Oil Demand	**99.0**	**99.3**	**100.6**	**100.8**	**93.0**	**82.8**	**91.5**	**93.7**	**93.7**	**95.8**	**98.2**	**98.6**	**98.2**	**99.2**	**100.7**	**101.0**	**99.9**	**90.2**	**96.6**	**99.8**
Total Oil Supply	**99.3**	**99.4**	**99.3**	**100.7**	**99.6**	**91.2**	**90.3**	**92.3**	**94.0**	**94.9**	**96.0**	**96.4**	**97.8**	**100.0**	**102.6**	**103.6**	**99.7**	**93.3**	**95.4**	**101.1**
OPEC Crude	30.6	30.0	29.3	29.6	28.6	25.9	24.3	25.3	26.6	27.1	27.4	27.5	28.5	29.8	31.3	31.8	29.9	26.0	27.2	30.4
OPEC Other Liquids	5.0	4.9	4.8	4.8	4.7	4.4	4.3	4.3	4.4	4.5	4.6	4.6	4.5	4.6	4.7	4.6	4.9	4.4	4.5	4.6
Non-OPEC Crude + Other	61.2	61.9	62.6	63.6	63.6	58.5	59.2	60.1	60.3	60.6	61.4	61.7	62.0	62.8	63.8	64.3	62.3	60.3	61.0	63.2
Processing Gain	2.6	2.6	2.6	2.7	2.6	2.4	2.5	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	2.6	2.5	2.7	2.8
Stock Change To Balance	+0.4	+0.1	-1.3	-0.1	+6.6	+8.4	-1.2	-1.4	+0.3	-0.8	-2.1	-2.2	-0.3	+0.8	+2.0	+2.6	-0.3	+3.1	-1.2	+1.3
Stock Change To Balance, mb	+13	+2	-40	-5	+201	+253	-35	-43	+9	-25	-65	-66	-9	+25	+60	+80	-8	+93	-37	+39
Spare Storage Capacity , mb	1,984	1,967	2,055	2,086	1,774	757	807	923	938	979	1,149	1,334	1,438	1,410	1,265	1,025	2,023	1,064	1,101	1,283

Source: J.P. Morgan Commodities Research. E: Estimate. *Observed stock change in OECD only. Balances as of Dec 4, 2020

Table 13: JPM Commodities Research Oil Price Deck

		2019	1Q20	2Q20	3Q20	4Q20	2020	1Q21	2Q21	3Q21	4Q21	2021	1Q22	2Q22	3Q22	4Q22	2022
Brent	New (Nov 20)	64	51	33	43	42	42	43	49	51	56	50	61	67	64	55	62
	Old (Oct 20)	64				39	42	43	45	49	52	47					
WTI	New (Nov 20)	57	46	28	41	37	38	41	47	48	53	47	57	63	60	51	58
	Old (Oct 20)	57				37	38	41	43	46	49	45					
WTI - Brent	New (Nov 20)	-7	-5	-5	-2	-5	-4	-3	-3	-3	-3	-3	-4	-4	-4	-4	-4
Forward Curve	Brent					45	43	49	48	48	48	48	48	47	47	47	47
	WTI					42	39	46	46	45	45	45	45	44	44	44	44

Source: ICE, NYMEX, Bloomberg Finance L.P., J.P. Morgan Commodities Research. Forecasts as of 27 November 2020.

The JPM Global FX Strategy team expects lingering effects of COVID-19 containment measures to remain threats

Ambiguous demand outlook on COVID-19 resurgence risk and vaccine hopes

On the demand side of the equation, the JPM Commodities team projects oil demand will recover ~7% to 96.6 mmbbl/d in 2021 (-3.3% v. 2019), as large disruption to mobility caused by COVID-19 containment measures eases. Global GDP is estimated to contract -4% y/y in 2020, followed by a robust 4.7% recovery in 2021 (the largest rebound since 2010). Our Global FX Strategy team expects the USD to show continued (but moderating) weakness in 2021, with the JPM USD index down -1.7% y/y. The potential for unexpectedly high growth and inflation on favorable vaccine outcomes leaves room for a possible USD rebound, as the curve could be disproportionately sensitive to risks of early policy exit by the Fed; this injects downside risks for the oil price. Positive vaccine prospects and easy monetary policy should help prop up the outlook for next year; however, an estimated 2.5% output gap for 2021, lingering income imbalances, and credit stress from a buildup in debt will represent the main threats post-COVID.

While these vaccine prospects provide a constructive outlook for global mobility (and in turn demand), obstacles still stand in the way of the link between infections and mobility completely separating. Preventative measures will need to continue to be taken even as the vaccine is distributed, and the risk of surges in cases will likely remain until herd immunity is achieved. Dispersed vaccinations could also continue to disrupt travel globally and more people may choose to remain working from home, preventing gasoline demand from normalizing immediately. As a result, the Commodities team does not expect demand to reach pre-pandemic levels (~100 mmbbl/d) until well into 2022.

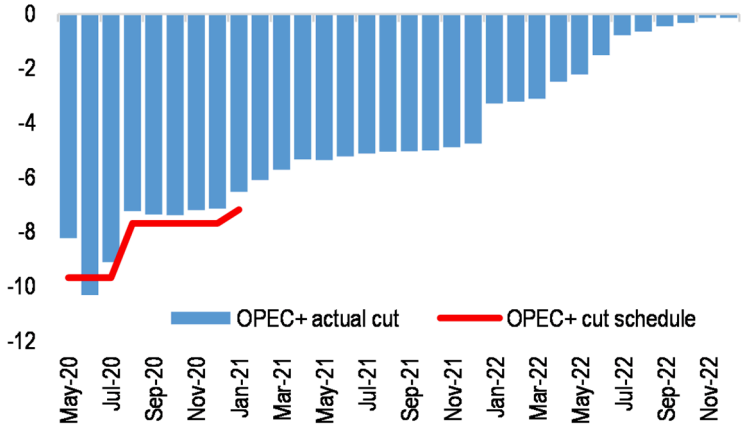
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

With U.S. shale tamed by financial markets and OPEC production underutilized, OPEC+ policy remains the linchpin for near-term supply dynamics

Supply outlook dominated by OPEC+ behavior and U.S. restraint

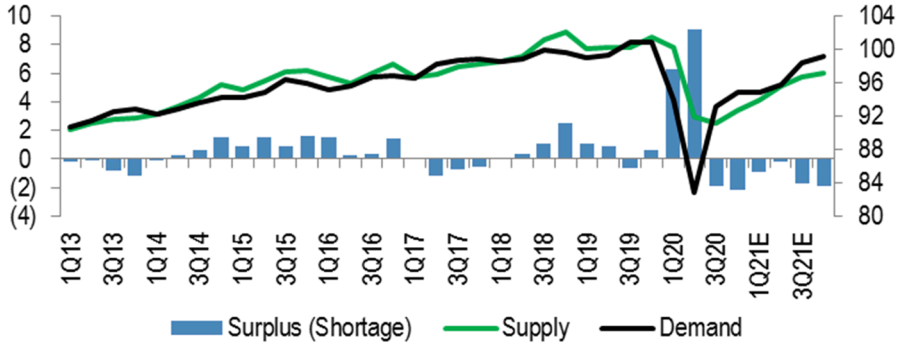
Oil supply in 2021 looks to be heavily influenced by the maintenance of OPEC+'s amended two-year strategic agreement, the purpose of which is to align the organization's production profile with demand while it continues to supply half of the barrels needed globally. While the original agreement called for production cuts to be tapered beginning in January (resulting in ~2 mmbbl/d of supply returning), OPEC+ compromised at its December meetings and agreed to add just ~500 kbbl/d. However, the decision came in opposition to collective expectations (including our own) that the organization would hold off on a production hike until at least April. An important aspect to note is the establishment of monthly meetings in which output can be revised in either direction (by no more than 500 kbbl/d) following the initial increase in January. In our view, member compliance with the agreement is even more crucial for oil prices now with supply set to increase and demand remaining up in the air. The Commodities team projects the global oil balance will remain in an average deficit of -1.2 mmbbl/d through 2021, with OECD inventories normalizing by late 2021.

Figure 110: OPEC+ Production Cuts (mmbbl/d)



Source: J.P. Morgan Integrated Oils Research, J.P. Morgan Commodities Research

Figure 111: …Allowing OPEC+ Barrels to Return with Demand



Source: J.P. Morgan Integrated Oils Research, J.P. Morgan Commodities Research

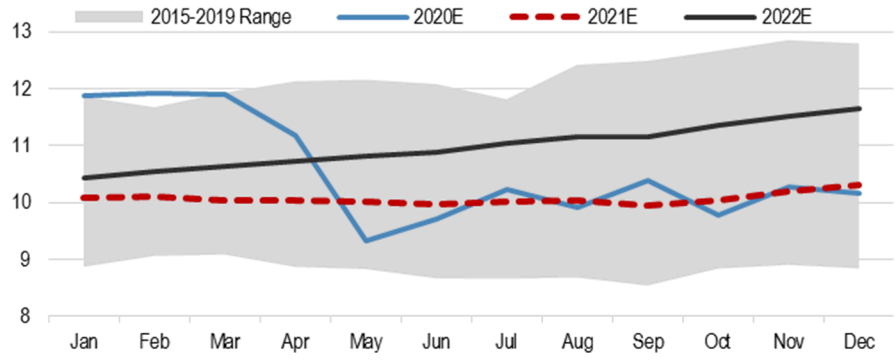
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Operator guidance indicates flat U.S. production at conservative capex levels

U.S. shale production looks to be reserved through 2021, while non-U.S., non-OPEC+ supply will rise only ~0.5 kbbl/d as longer-term investments come back online. In the latest edition of our E&P Budget Watch series, the overall 2021 messaging from those offering guidance across the U.S. companies we track was consistent in calling for more or less flat production from 4Q20 levels with restrained capital spending. Our production forecasts are in line with this guidance, and we anticipate producers will operate at maintenance capex levels in 2021 with a larger focus on generating cash and de-risking balance sheets.

However, the unknowns of oil demand regarding COVID-19 (as well as U.S. politics) leave this preliminary spending guidance on flat production easily subject to change in our view. The decision by OPEC+ to cautiously increase production in January and potentially revise output monthly may also complicate the outlook if decision-making becomes erratic. The Commodities team currently forecasts total U.S. crude production to average 10.8 mmbbl/d (down -0.9 mmbbl/d y/y) in 2021 and exit the year relatively flat at 11.1 mmbbl/d (up +0.2 mmbbl/d y/y) in 4Q21, assuming a return to growth around June with a more notable ramp in September. This is in line with our U.S. Integrated Oils & Refining colleagues' base case of >11 mmbbl/d, assuming WTI prices in the ~$40s.

Figure 112: U.S. Crude Production (mmbbl/d)



Source: EIA, J.P. Morgan Commodities Research

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Natural Gas Macro: U.S. Production Likely to Hold Flattish y/y in 2021

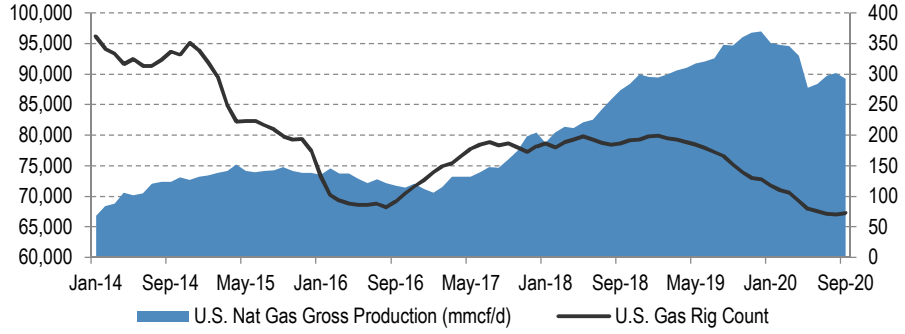
Comparably Steadier D&C Activity in Gassier Basins Offers OFS Stability Near-Term, But Also Less Upside Optionality

U.S. gas rigs fell -48% y/y in 2020, less than the -55% y/y decline seen by the overall L-48 rig count

Gas drilling proved more resilient than oil drilling in 2020

2020 broke the trend witnessed in 2017-2019 of meaningful increases to U.S. natural gas production with a -600mmcf/d y/y decline to supply (-0.7%). The drop off in associated gas volumes from oil-focused drilling was a significant factor in reduced volumes, and lent support to dry gas-oriented drilling in 2020. As a result, gas-focused E&Ps cut budgets by less than oil-centered peers (-38% v. -51% y/y), and subsequently the gas rig count proved more resilient than the overall L-48 land rig market (2020 gas rig count -48% y/y v. L-48 -55%, oil rigs -56%). Within the gassier basins, the Haynesville was the most steady, falling only -29% y/y, while the Marcellus/Utica was down -45% y/y in 2020.

Figure 113: U.S. Gross Natural Gas Production (mmcf/d, LHS) v. Gas Rig Count (RHS)



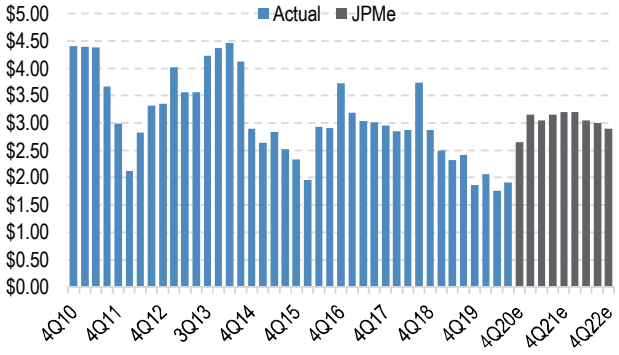
Source: EIA, Baker Hughes.

Our E&P team assumes gas production of 89.5 Bcf/d in 2021, -0.3% lower y/y

Expect flattish production growth y/y, with November already hitting 2021 avg.

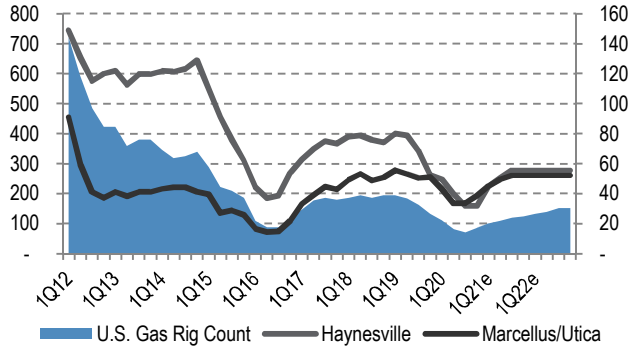
Heading into 2021, we anticipate U.S. natural gas production to remain largely flat, with our E&P colleagues modeling a -0.3% y/y decline in 2021 to 89.5 Bcf/d. November volumes have increased materially (+2 Bcf/d m/m), largely driven by the Northeast as shut-in volumes return to the market and more DUCs are completed, lifting volumes to a level already near the 2021 projected average.

Figure 114: JPM Natural Gas Price Forecast ($/MMBtu)



Source: J.P. Morgan Natural Gas Research.

Figure 115: JPM Gas Rig Count Forecast



Source: Baker Hughes, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 116: JPM Natural Gas Lower-48 Supply / Demand Balance

	2020E				2021F				2020E	2021F
	1Q20	2Q20	3Q20	4Q20	1Q21	2Q21	3Q21	4Q21		
Total Supply	97.9	93.1	92.9	92.7	93.9	93.4	94.6	95.6	94.1	94.4
Dry Gas Production	93.1	89.2	88.5	88.3	88.7	88.9	89.8	90.7	89.8	89.5
Net Canadian Imports	4.7	4.0	4.4	4.4	5.2	4.5	4.9	4.9	4.4	4.9
LNG Imports										
Total Domestic Consumption	97.8	69.3	74.9	83.7	96.3	67.3	73.6	83.7	81.4	80.2
Power Generation	29.5	29.1	39.2	26.9	27.4	27.7	37.7	25.9	31.2	29.6
Industrial	23.8	19.1	20.4	22.9	22.6	18.9	20.6	23.1	21.6	21.3
Residential/Commercial	36.3	14.0	8.0	26.2	38.2	13.6	8.0	27.0	21.1	21.7
Lease, Plant, and Fuel	8.2	7.1	7.2	7.6	8.2	7.2	7.3	7.7	7.5	7.6
Total Exports*	13.8	11.5	10.7	15.6	16.8	14.5	14.8	16.5	12.9	15.7
Pipeline to Mexico	5.4	5.2	6.3	6.1	6.4	6.0	6.4	6.1	5.7	6.2
Feedgas for LNG exports	8.5	6.3	4.4	9.4	10.4	8.6	8.4	10.4	7.2	9.4
Net Injection to storage**	-13.7	12.4	7.3	-6.5	-19.2	11.5	6.3	-4.6	-0.1	-1.5
Net Injection to storage (Bcf)**	-1236	1137	674	-601	-1726	1045	576	-423	-54	-550
End of period storage level (Bcf)	1986	3077	3756	3155	1429	2474	3051	2627	3155	2627

Note: *Total exports do not include exports to Canada. **Withdrawals represented as a negative number.
Source: Genscape, Bloomberg Finance L.P., J.P. Morgan E&P Equity Research.

Gas demand set to fall -1-2% y/y in 2021 on reduced power generation

U.S. gas demand fell -5.5% y/y in 2020, and our E&P colleagues anticipate a further -1.4% falloff y/y in 2021. The decline should be driven mostly by lower power generation demand, while industrial demand is likely to stabilize in the coming months. A warm start to the winter also suggests little residential and commercial support. Gas exports however look set to increase +21% y/y as LNG continues to run near full capacity and gas exports to Mexico are expected to grind higher.

We model rig counts in the gassier basins growing in 2021, with more sequential upside for their (larger) oily counterparts

Gassier basins to offer stability for OFS utilization in 2021, favoring oily ones

Across the gassier basins, as DUC inventories reach more normalized levels in 1H21 we anticipate incremental rigs will go back to work in these regions to sustain production levels. As such we model the Marcellus/Utica and Haynesville averaging 52/50 rigs in 2021, up from 31/38 QTD in 4Q, or about +35% higher y/y for each. While we think these basins likely have less upside optionality in 2022+, the near-term stability offers a benefit to service providers seeking utilization. Among the land drillers, PTEN has the most exposure to the regions with ~25% of its active fleets in the Marcellus/Utica and 15-20% in the Haynesville. For the pumpers, NEX has a leading position in the Marcellus/Utica, with HAL and PTEN also competing, while HAL is a large provider in the Haynesville. LBRT will gain a foothold in gas basins for the first time upon the completion of its acquisition of OneStim from SLB.

Figure 117: JPM Natural Gas Research Price Forecast

In $/MMBtu	1Q20	2Q20	3Q20	4Q20	2020	1Q21	2Q21	3Q21	4Q21	2021	1Q22	2Q22	3Q22	4Q22	2022
Current Forecast*	...	...	...	2.65	2.10	3.15	3.05	3.15	3.20	3.14	3.20	3.05	3.00	2.90	3.04
Previous Forecast**	...	...	...	2.50	2.06	3.25	3.15	3.15	3.20	3.19	...	...	...	...	...
Actual To Date	2.07	1.76	1.91	2.65	2.10	...	...	...	...	...	...	...	...	...	...

All forecasts are averages of the contract months within the quarter. Actual to date prices are as of November 24, 2020. *As of November 24, 2020. **As of September 10, 2020.
Source: J.P. Morgan Natural Gas Research.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Global LNG FIDs on Pause, but the 'Transition Fuel' Still a Force for the Cycle(s) Ahead

We view LNG as both a transition and a destination fuel, and could see +100mmpta capacity expansion in the next decade

We contend that LNG will remain an important piece of global energy supply

We continue to like LNG as both a transition and destination fuel for the cycle(s) to come, and think that a shift in sentiment among investors to write-off LNG on their way to the warm embrace of (largely unproven at scale) green hydrogen technology is overly bearish on the commodity. Even if the green hydrogen code is eventually cracked, global emissions can be tamed most effectively over the next decade through coal-to-gas demand switching, particularly in the Eastern Hemisphere. While there is a case to be made that the energy transition moves so quickly that LNG is passed over, we agree with BKR's view that the industry will need +600mmtpa of nameplate capacity to meet demand by 2030. Even after recent FIDs are factored in, we think this will necessitate investment in +100mmtpa additional capacity over the next decade. The current downturn likely will result in a pause for sanctioning in the near-term, but we see scope for an investment cycle to reemerge from 2022 and beyond followed by typical 2-3 year construction phases, keeping the industry on pace for our 2030 demand outlook.

2020 ends with important U.S. and Mexico sanctions; Qatar NFE on tap

Towards the end of 2020 we saw the sanctioning of both Sempra's Costa Azul (2.5mmtpa) and Cheniere's Corpus Christi Stage 3 (9.5mmtpa). Near-term, Qatar's North Field East expansion (32mtpa) looks set to be officially sanctioned soon, but awards for its two EPC contracts have slipped into 1Q21, likely meaning the same for FID. Subsequently, Qatar's North Field South (16mmtpa) is expected to FID in 2022 and ramp production in the late 2020s. Looking further out, the Papua LNG two-train development in Papua New Guinea is now expected to move forward independent of the PNG LNG Train 3 (which looks off the table for now), a positive for the project which has been delayed by negotiations; WoodMac expects a 2023 FID to now be in the works.

Table 14: Short List of Global LNG Projects

Location	Project	Operator	FID Target	Nameplate Capacity (mmtpa)
USA	Plaquemines LNG	Venture Global Partners	Possible 2021	20.0
USA	Rio Grande LNG	Next Decade	Possible 2021	13.0
USA	Driftwood LNG	Tellurian	Possible 2021	11.0
USA	Port Arthur Phase 1	Sempra	Possible 2021	11.0
USA	Freeport Train 4	Freeport LNG	Possible 2021	5.4
Russia	Obskiy LNG	NOVATEK	Possible 2021	5.0
Australia	Pluto Expansion	Woodside	Possible 2021	4.5
Canada	Woodfibre LNG	Pacific Oil and Gas	Possible 2021	2.1
Mozambique	Rovuma LNG (Area 4)	ExxonMobil	Possible 2021	15.2
Qatar	Qatar North Field South	Qatar Petroleum	Probable 2022	16.0
Papua New Guinea	Papua LNG	Total	2023	5.3
Maurtania/Senegal	Tortue Phase 2&3	BP	2023+	7.5
Total				**116**

Source: Wood Mackenzie, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

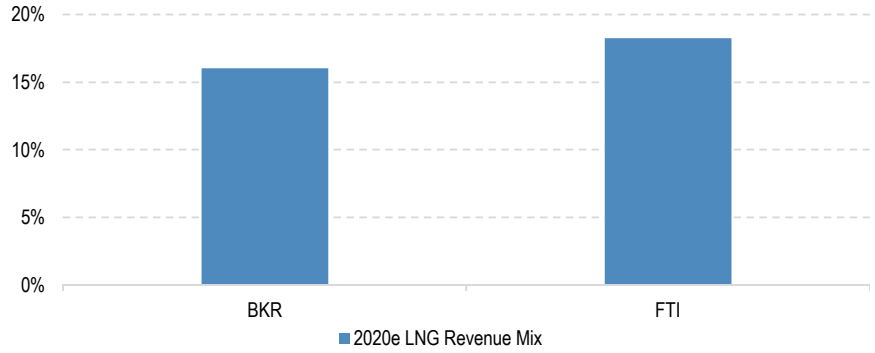
BKR expects 3-4 LNG FIDs next year

BKR and FTI advantaged v. peers this cycle given LNG exposure

We think Baker Hughes is one of the few companies in our coverage with the ability to generate higher EBITDA cycle over cycle, boosted by a growing TPS business with sizable LNG mix. With skepticism around LNG programs progressing smoothly through this downturn, investors seemed overly critical earlier in the year on order prospects going forward. We remain confident in a ~$5bn annual floor, helped by the segment's aftermarket spend that can be 2-3x the original equipment's value over a 25-30 year life. For equipment orders, BKR's opportunity per mmtpa is around $50mm but can range significantly (~$30-70mm) depending on project scope. BKR sees three or four FIDs on the horizon in 2021 which we think could amount to total inbound similar its Qatar NFE award in 2020 (~$1bn).

FTI will also be getting in on the action in Qatar (after doing its FEED) to the tune of ~$1bn in orders. The project will be nearly twice the size of XOM's Rovuma which remains a candidate for FID in 2021 but the U.S. Major is searching for cost reductions (i.e. pricing concessions), potentially pushing sanctioning further out. However the energy mix shifts in the coming years (more likely decades), we think BKR and FTI are both employing sound strategies to build upon leadership positions and play central parts of the supply chain fueling the energy transition.

Figure 118: LNG Revenue Mix



Source: Company filings, J.P. Morgan estimates.

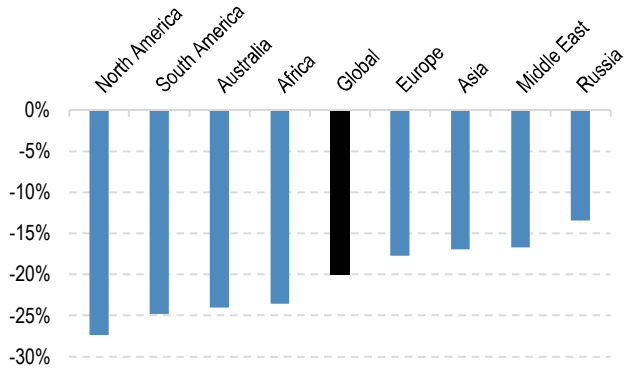
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Global E&P Capex Outlook: Downside Risks Near-Term On Macro Uncertainty and "Do More with Less" Mentality

We expect spending to be down MSD y/y in 2021; expecting a better cycle in 2023 and beyond

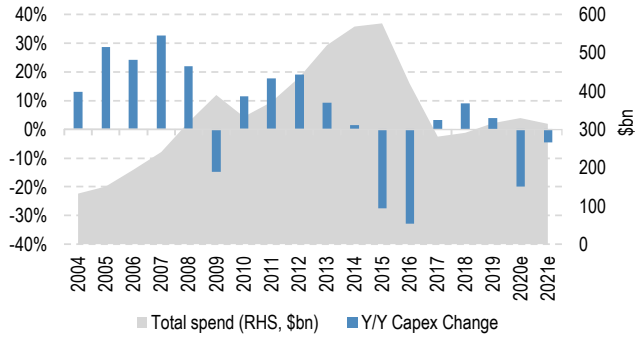
Global upstream spend is looking to be down ~20% y/y in 2020, compared to ~30% declines in 2015 and 2016, given there was simply less to cut even in the dire environment this year presented. E&P spend was most negatively impacted in North and South America, with Asia, ME and Russia exhibiting some relative resilience. In 2021 we forecast global spend to be flat to down 10% with a base case of NAM and int'l both being down MSD. Some NAM operators have signaled ~4% lower capex but we see downside risk there as the full dataset comes in 1Q21. While we still think 2022 is too early to see a notable rebound, we expect global spend to be up 5-10% y/y followed by further momentum in 2023. For a reasonable investment horizon, we have yet to be compelled to dip our toe into the OFS pool, especially with what we view as overly bullish recoveries priced into the stocks during the most recent rally.

Figure 119: 2020e Capex Change by Region



Source: J.P. Morgan estimates, company data, Rystad.

Figure 120: Upstream Capex ($bn, RHS) and Y/Y Growth (%, LHS)



Source: Company reports, J.P. Morgan estimates.

NAM Onshore Capex in Muted Ascent post-2020 Implosion

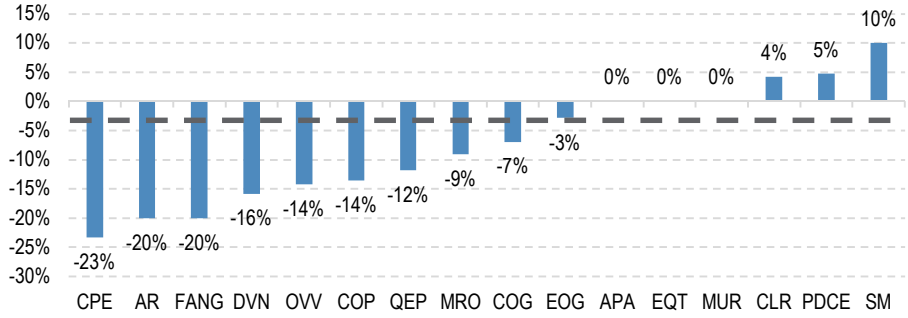
We think 2021 U.S. E&P capex will be flat to down -10% y/y based on preliminary guidance, which at least suggests sequential improvement

First look at U.S. E&P 2021 budgets suggests -MSD y/y decline

While many of the U.S. E&Ps are likely to hold off on announcing 2021 spending plans until 4Q20 earnings, 16 E&Ps included in our E&P Budget Tracker have already made comments on 2021 spending, suggesting a -4% decline in 2021 capex y/y accompanied by generally flat crude production from 4Q20 levels. These are however preliminary guides and come with important caveats like assuming a stable WTI strip from late-October/early-November levels, and the oil demand recovery representing the largest "known unknown" depending on the success of COVID-19 vaccinations and economic reopening. Among those offering guidance, ten are planning capex cuts y/y (-14% on average), three anticipate flat spending, while three others expect to grow capex (+6% y/y on average). Given the significant weighting on 1Q20 in 2020 budgets (~40%), flat y/y capital allocation implies directionally higher quarterly spending off of 2H20 levels, consistent with our view for rising NAM OFS demand early in 2021. U.S. E&P messaging on reinvestment rates has been fairly consistent, with many prominent operators (including DVN, MGY, MRO, OVV, PXD, and XEC) pledging to keep CFO reinvestment of 65-80% at mid-cycle pricing (v. +120% last cycle) and to allocate any excess FCF to balance sheet clean up and shareholder cash returns, a theme reiterated during our recent Permian Tour.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 121: Preliminary 2021 Capex Guides



Source: Company reports, J.P. Morgan estimates.

Majors' pullback on L-48 spending shrinks an assumed source of stability

At one time, U.S. Oil Services welcomed the majors' bulking up in Lower-48 as a ballast of steady demand. While service companies still highly value work with the majors, their demands has proven to look and smell a lot more like the rest of the U.S. E&P complex. As their multi-year, mega projects abroad have less capital flexibility, both XOM and CVX are responsibly flexing their budgets in shale. Further, recent guidance updates for capital spending from XOM and CVX suggest a less robust allocation to L-48 development in the coming cycle. Exxon maintained its bogey of $16-19bn capex in 2021 (implying a ~25% y/y reduction at the midpoint) but cut its long-term capex target to <$25bn through 2025. While the longer-term target of <$25bn through 2025 is down from the $30-35bn XOM guided at its Analyst Day in 2019, it came as little surprise to our Integrated colleagues. CVX's initial 2021 guide stands at ~$14bn (down >20% y/y), and the company followed suit in reducing its longer-term capex expectations, lowering its 2022-25 capital and exploration budget to ~$14-16bn (from ~$19-22bn). Our Integrated peers think that this range should allow for relatively flat production over time (2021+).

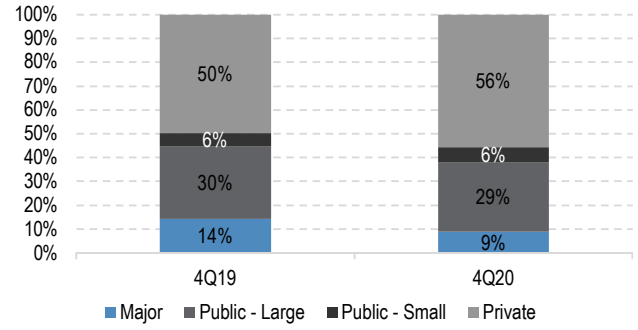
U.S. E&P capex forecast implies higher 2021 D&C activity v. 2H20 levels

Flat-to-down 2021 U.S. capex suggests the L-48 rig count reaches the high-300s, frac spread count ~180 by 2H21

U.S. operators were quick to recognize the realities of the 2020 economic downturn, and moved to rapidly slash 2020 spending expectations in March and April. The resulting -50% reduction in capex y/y in 2020 was accompanied by a -55% y/y decline in the rig count (-501 rigs), assuming the L-48 exits December at ~320 active rigs in accordance with our rig count forecast. 2Q20 accounted for the majority of the reduction (a jaw-dropping -456 rigs laid down from 3/30 to 6/30), though the trough didn't come until mid-August. We expect the (modest) upward slope in drilling seen since (+40% or +93 rigs since 8/14) will continue into 1H21 as operators compensate for activity falling below run rate maintenance levels for much of 2020 and seek to shore up 2021 production. We model the U.S. land rig count rising from an average of 291 in 4Q20 to 342/360 in 1Q21/2Q21. By mid-2021, we anticipate that most E&Ps will be running at or near sustaining levels, suggesting only limited upside through the balance of the year. As such we expect the L-48 to average ~380 active rigs in 2H21, resulting in a 2021 average rig count of 365 (v. 418 in 2020, -13% y/y).

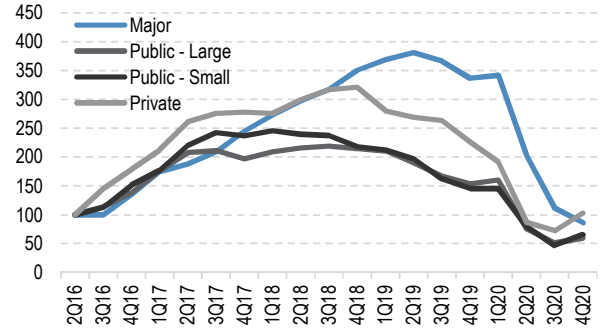
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 122: Rig Count by Operator Type 4Q19 v. 4Q20 QTD



Source: Enverus, J.P. Morgan estimates.

Figure 123: Change in Rig Count by Operator Type Since 2Q16 Trough

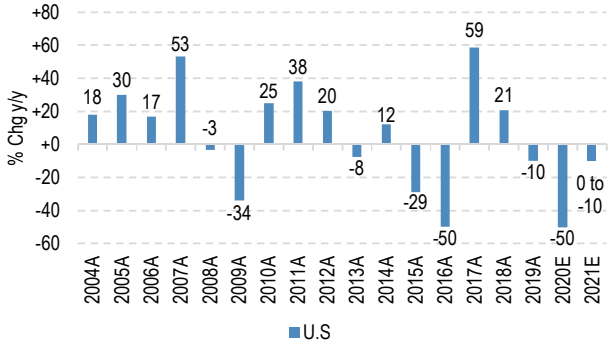


Source: Enverus, J.P. Morgan estimates.

But completions should lead drilling for at least 1H21

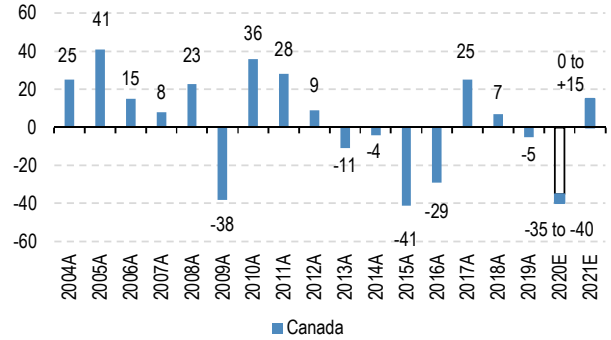
On the completions side, the U.S. frac spread count experienced even more volatility in 2020, falling from 300+ active fleets in February to ~75 by May (-75% or -230 fleets), when oil well completions came to a near standstill. The count has since recovered to ~120 fleets in November (+60% or +45 fleets since the trough) as E&Ps have allocated more capital to completing the large DUC backlog (DUCs account for ~60% of oil well completions from August to November). In 2021 we expect demand for frac spreads to accelerate in 1H21, reaching ~180 by mid-year. Similar to rig demand, however, we think the frac fleet count will more-or-less plateau near this level, as the DUC backlog should largely normalize into 2H21. With E&P guidance to invest incremental FCF in balance sheet management and shareholder returns, we doubt even a rally in WTI into the low-$50s would prompt significantly more completions work near-term.

Figure 124: U.S. Independent Capex Y/Y Change



Source: Company reports, Bloomberg Finance L.P., and J.P. Morgan estimates.

Figure 125: Canadian Independent Capex Y/Y Change



Source: Company reports, Bloomberg Finance L.P., and J.P. Morgan estimates.

Our base case for Canadian E&P capex suggests a flat to +15% y/y change in spending

Canadian capex set to increase in 2021 after below-sustaining spending in 2020

With drilling activity already facing challenges in Canada last year, capex reductions made by Canadian E&Ps in 2020 were severe but slightly shallower y/y than those from U.S. counterparts (-35-40% y/y). Heading into 2021 we anticipate that Canadian spending will be modestly higher y/y (JPMe flat to +15% y/y) as many E&Ps cut spending to below sustaining levels during 2020. An important outlier among Canadian E&Ps is MEG, which recently guided $260mm capex in 2021, a +70% y/y increase, as the company intends to ramp up production in 2021 on a more supportive commodity price outlook after reigning in investment in 2020 (-25% y/y). Also of note is the merger of CVE and HSE, which our Integrated colleagues believe will reduce sustaining capex from an aggregate of $2.55bn on a standalone basis in 2020 to $2.4bn for the combined company in 2021 (-6% y/y).

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

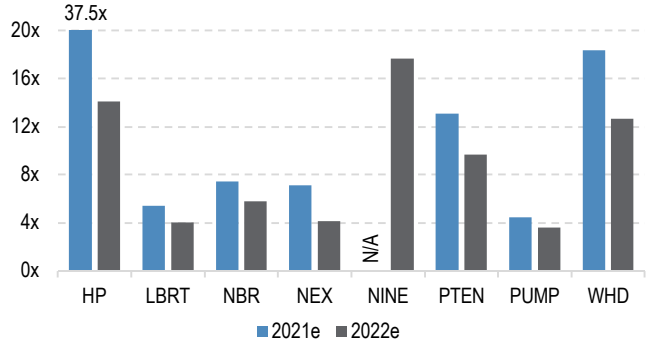
North America: Opportunities for Offense

Activity Build off 4Q20 Levels Creates Favorable Setup for Pumpers v. Drillers

We see near-term upside optionality among select NAM stocks that look cheap on "normalized", particularly among the pumpers

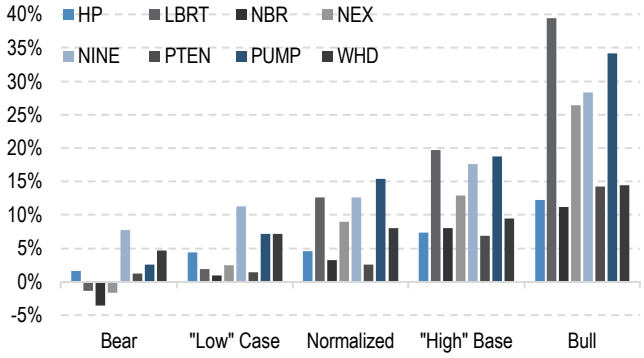
With North American D&C activity rebounding from 2020 troughs in 4Q20, we expect to see demand for NAM OFS to continue its march higher in 2021 (though still well off 1Q20 levels). In the recent vaccine-led rally, investors have shown a willingness to credit NAM stocks for an improved demand outlook in the coming years. Still, we believe there is good upside optionality among select U.S. onshore-focused stocks within our coverage that look relatively cheap on a "normalized" basis. In particular, we favor the pressure pumpers, which we think are entering a much more favorable environment than in the past thanks to equipment retirements and attrition resulting in a market we expect to tighten through next year and into 2022. As such we think the group's MSD EV/2021 EBITDA multiples and low-DD FCF/EV yields on our normalized assumptions screen relatively attractively.

Figure 126: NAM Onshore 2021/2022 EV/EBITDA multiples



Source: Bloomberg Finance L.P., J.P. Morgan estimates.

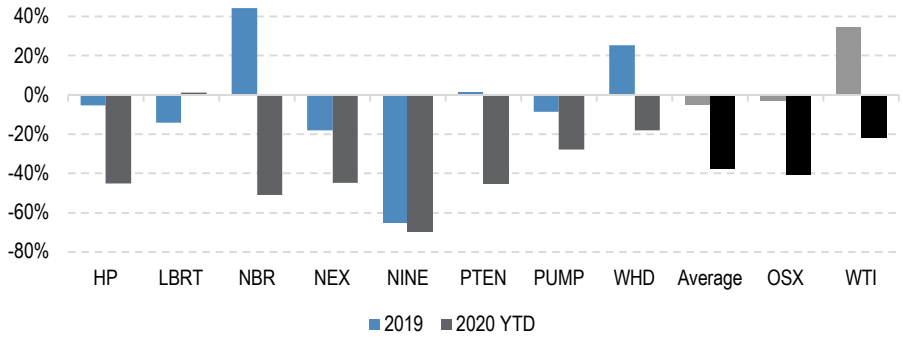
Figure 127: NAM FCF/EV Yield Estimates by Scenario



Source: Company filings, J.P. Morgan estimates. Note LBRT is pro forma for OneStim. :

Though prospects for future NAM D&C demand improved over the course of 2020, our NAM coverage traded relatively in-line with the rest of OFS, averaging a -38% YTD decline (v. -41% OSX). Within the group, pumpers performed relatively well, led by a strong result from M&A-assisted LBRT (+1% YTD in 2020). Meanwhile the drillers lagged, falling -47% on average in 2020, with all three performing fairly similarly. Into 2021 we continue to view the land drillers as disadvantaged relative to pumpers, with less rate-of-change potential in an oversupplied super-spec market.

Figure 128: Select NAM Onshore Stock Performance, 2019 and 2020 YTD



Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Our normalized activity assumptions call for a low-to-mid 600s rig count and mid-200s frac fleet count mid-cycle, suggesting the frac market tightens before drilling

Normalized activity outlook suggests pumping tightens before drilling

Our normalized earnings analysis across our coverage is predicated on assumptions for mid-cycle activity across an assortment of scenarios for the coming cycle (see View to 2025 and Fall Playbook). In North America, we see current activity levels as still well below our normalized mid-cycle assumptions, in which we think the L-48 will need to average a low-to-mid 600s rig count and mid-200s frac fleet count. With our assumption that the useful frac hp supply has fallen to 12-12.5mm hp, we believe the frac market is likely to tighten to a level sufficient to drive better economics for the pumpers well before the drilling market, where we estimate there are ~675 super-spec rigs and where equipment attrition is much less of a factor.

Figure 129: JPM Normalized Scenarios for the Coming Upstream Cycle

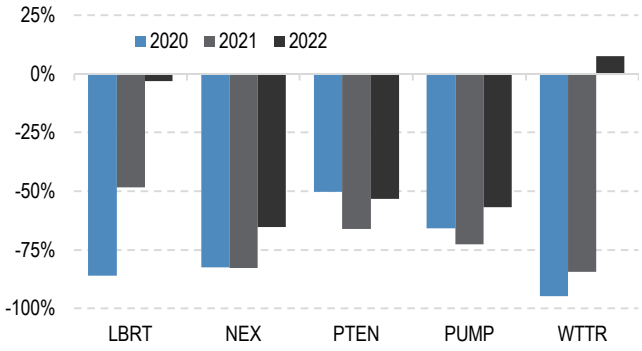
	Prior Cycles		Normalized Cases				
NAM	**'09-'14**	**'15-'19**	**Bear**	**"Low" Base**	**Normalized**	**"High" Base**	**Bull**
Average WTI Price	$87	$53	Low-$40s	Low-$50s	Mid-$50s	Low-$60s	$70+
Annual Oil Production Growth (mmbbl/d)	+750	+1,038	Flat	+500	+600	+1,000	+1,500
Average U.S. Land Rig Count	1,712	870	400	550	635	750	1,000
Average U.S. Oil Rig Count	961	697	330	480	550	660	900
Average U.S. Gas Rig Count	751	172	70	80	85	90	100
Average U.S. Frac Spread Count		346	163	225	250	300	425
International							
Average Brent Price	$96	$58	High-$40s	High-$50s	Low-$60s	High-$60s	$80+
Average Int'l Rig Count	1,186	1,033	800	850	880	950	1,050
Average Int'l Land Rig Count	881	802	650	675	690	725	800
Average Int'l Offshore Rig Count	305	230	150	175	190	225	250

Source: Baker Hughes, Genscape, J.P. Morgan E&P Research, J.P. Morgan OFS estimates.

Favor completions-levered stocks with cheap valuations and strong operations

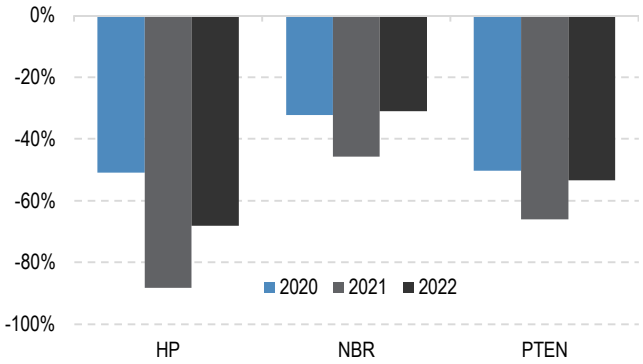
We like the upside optionality among completions-levered smid-caps with good balance sheets and strong operational track records. This makes NAM the one group in which we recommend an "offense" strategy to complement our general stance of sticking with defensive, backlog-heavy companies. As such we maintain our Overweight ratings on PUMP and NEX, both of which we think fit this description nicely. LBRT checks many of these boxes as well, but we see the stock as more of a consensus favorite following its significant outperformance after the OneStim acquisition was announced (LBRT +74% since 8/31, frac peers +39%, OSX +30%), and hence prefer to stay Neutral on the shares. Outside of the pumpers, we like WHD as well for its strong competitive position, prospects for further market share penetration, and clean balance sheet.

Figure 130: Frac-levered 2020-2022 EBITDA Consensus Revisions



Source: Bloomberg Finance L.P.

Figure 131: Land Driller 2020-2022 EBITDA Consensus Revisions



Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

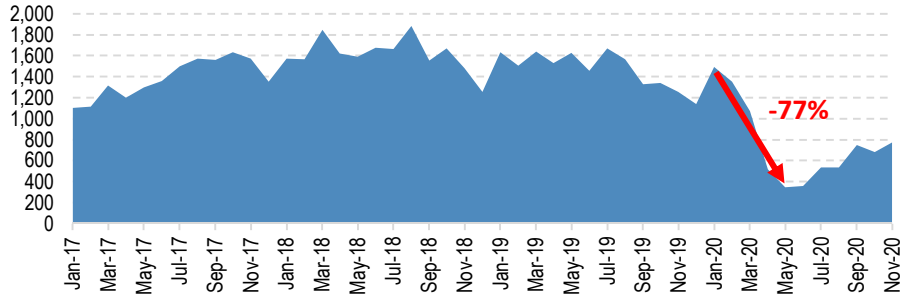
Pumping: "More Pain" Finally Upon Us, "More Gain" Next?

We estimate an average frac fleet count between 160-180 in 2021, with some of the variance driven by higher mix of simul-frac crews

2020 witnessed a historic decline for U.S. frac activity, with E&P's moving quickly to hit the brakes on completions programs in the spring in the wake of plunging oil demand. With completions representing the lion's share of the well cost and pressure pumping contracts generally shorter-term, frac was the clear choice where operators could flex budgets lower quickly. As a result U.S. frac starts plummeted by -77% between January and May of this year. As 2020 progressed and the crude demand outlook stabilized, E&Ps slowly began to add frac spreads and end 'frac holidays'.

In subsequent months frac starts more than doubled, and now appear poised to finish the year strong, with only mild holiday downtime expected in December (a contrast to budget exhaustion-induced slowdowns in prior 4Qs). Still, frac activity is currently well below sustaining levels. We believe the active fleet count will need to rise over the course of 2021 from the low-100s today to a count of ~180 in 2H21 to achieve E&P production targets, setting up a 2021 fleet count average of 160-180 (email us for our proprietary frac supply-demand model). **We see potential for some price recovery into 2022, but such a scenario requires continued supply discipline, while growing adoption of simul-frac risks creating more "phantom" capacity.**

Figure 132: Monthly Frac Starts Declined -77% from January to May 2020

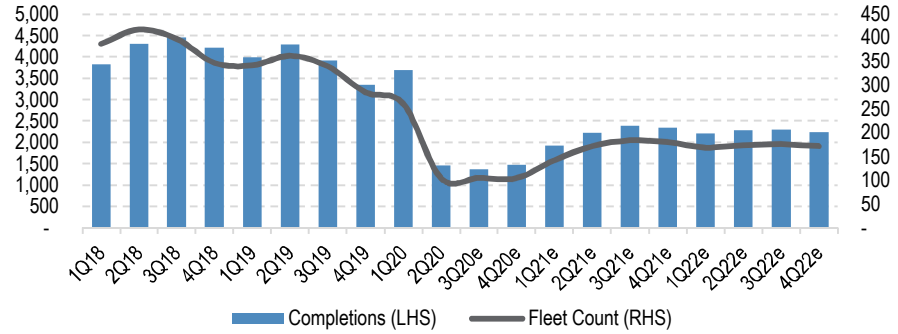


Source: Rystad

Attrition finally manifests in ~40% of nameplate capacity sent to frac graveyard

Accompanying the slowdown in activity was a purge of old equipment from the market as it became clear that lower-quality hp was unlikely to go back to work again. We estimate that +5mm hp exited the market in 2020. This still leaves the industry oversupplied, but with more consolidation of useful equipment among the frac "haves" we see some hope of a better path forward emerging, setting up a "more pain, more gain" tailwind for the survivors. In the meantime, investors should expect pricing and margins to remain near current levels (i.e. trough-ish).

Figure 133: U.S. Land Completions (LHS) and Frac Fleet Count (RHS)



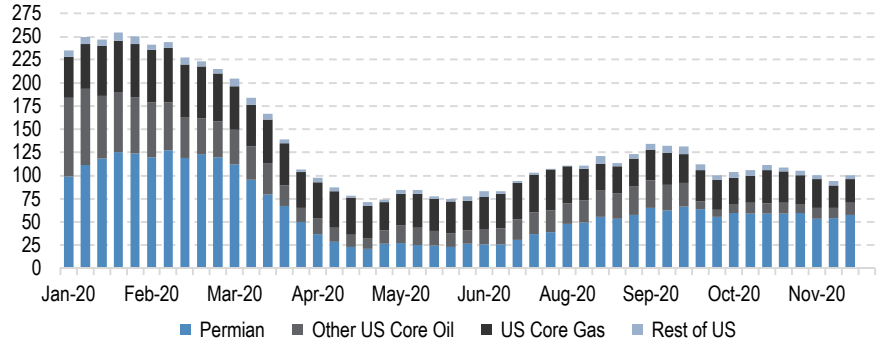
Source: Rystad, J.P. Morgan Estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Permian to drive incremental frac demand, DUCs become less of a factor

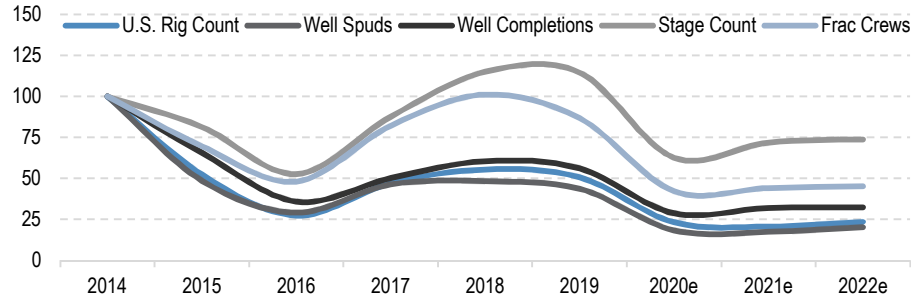
Oil basins were hit hardest by the decline in pumping demand in 2020, but the Permian fared much better than its other oil basin counterparts, the a frac fleet count down -42% YTD v. -85% for the other core oil basins. We expect this dynamic to continue in 2021, with the Permian accounting for most of the frac demand ramp up, likely weighted towards 1H21. Of the oil-focused frac jobs started since the trough, DUCs have accounted for 70-80% as operators work through a large backlog. We think the DUC count will continue to be a source of more completions work in 2021, but as balances normalize, more rigs and spuds will be needed to sustain production.

Figure 134: Frac Fleet Count by Basin



Source: Rystad.

Figure 135: Key U.S. Activity Metrics Indexed to 2014



Source: Rystad, Baker Hughes, J.P. Morgan Estimates.

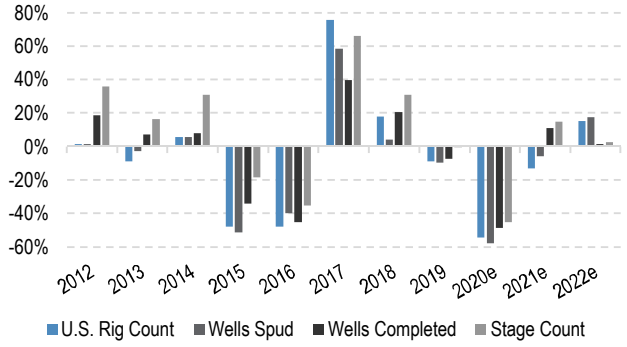
Table 15: JPMe Frac Supply-Demand Summary

													Y/Y Change				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020e	2021e	2022e	2018	2019	2020e	2021e	2022e
U.S. - Oil Rigs	982	1,359	1,373	1,525	746	409	703	841	774	344	268	293	20%	-8%	-56%	-22%	9%
U.S. - Gas Rigs	886	556	383	332	226	100	172	190	169	88	115	144	10%	-11%	-48%	30%	26%
U.S. Offshore Rigs	32	47	56	57	35	23	20	19	23	15	17	20	-7%	22%	-33%	9%	18%
U.S. Total Rigs	**1,875**	**1,919**	**1,761**	**1,860**	**974**	**510**	**876**	**1,032**	**943**	**434**	**383**	**437**	**18%**	**-9%**	**-54%**	**-12%**	**14%**
Well Spuds	40,360	41,010	39,904	42,196	20,519	12,340	19,558	20,412	18,438	7,749	7,351	8,558	4%	-10%	-58%	-5%	16%
Well Completions	20,234	23,971	25,696	27,715	18,179	9,943	13,911	16,786	15,542	7,980	8,863	8,989	21%	-7%	-49%	11%	1%
Land Stage Count ('000)	231	314	366	479	390	253	420	551	549	300	345	354	31%	0%	-45%	15%	3%
Stages per Well	11.4	13.1	14.2	17.3	21.5	25.4	30.2	32.8	35.3	37.6	38.9	39.4	9%	8%	6%	3%	1%
Frac Spread Assumptions																	
Stages per Shift	2.3	2.8	4.2	3.7	4.2	3.6	3.2	3.5	3.7	3.8	4.2	4.2	10%	4%	4%	10%	1%
% 24/7 Work	25%	35%	45%	55%	50%	60%	64%	65%	65%	73%	73%	72%	2%	0%	12%	0%	-1%
% 12/5 Work	75%	65%	55%	45%	50%	40%	36%	35%	35%	27%	27%	28%	-3%	0%	-23%	0%	3%
Shifts per Day	1.3	1.4	1.5	1.6	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1%	0%	5%	0%	-1%
Stages per Day	2.9	3.8	6.0	5.7	6.3	5.7	5.2	5.8	6.0	6.6	7.2	7.3	11%	4%	9%	9%	1%
Days Worked per Year	285	295	305	315	310	320	324	325	325	333	333	332	0%	0%	2%	0%	0%
Stages per Year	582	792	1,291	1,252	1,463	1,372	1,445	1,611	1,668	1,855	2,037	2,052	11%	4%	11%	10%	1%
Days to Frac Well	3.9	3.4	2.4	3.0	3.4	4.4	5.8	5.6	5.9	5.7	5.4	5.4	-2%	4%	-2%	-6%	0%
Pressure Pumping Demand																	
Frac Crew Demand	397	397	283	383	267	184	315	387	332	162	169	172	23%	-14%	-51%	5%	2%
Rig-Frac Crew Ratio	4.6	4.7	6.0	4.7	3.5	2.6	2.7	2.6	2.8	2.6	2.2	2.4	-4%	6%	-7%	-16%	12%
HP Demand (mm hp)	**10.9**	**11.9**	**12.4**	**14.6**	**10.7**	**6.2**	**14.2**	**16.5**	**14.2**	**7.0**	**7.3**	**7.5**	**16%**	**-14%**	**-51%**	**4%**	**2%**

Source: EIA, Rystad, J.P. Morgan estimates.

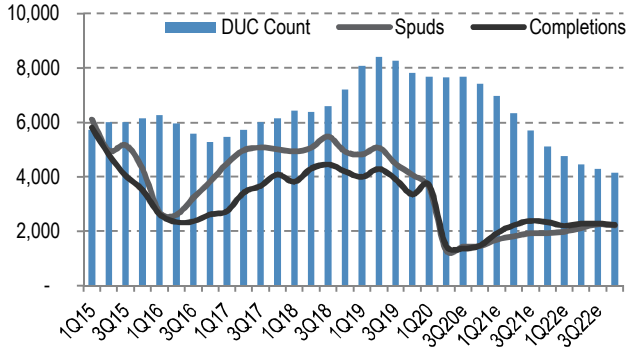
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 136: U.S. Rig, Spud, Completions, Stage Count Growth (% Y/Y)



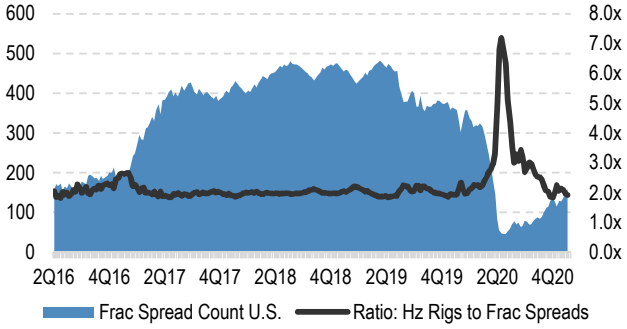
Source: EIA, Rystad, J.P. Morgan estimates.

Figure 137: U.S. DUC Count, Wells Spud and Completions



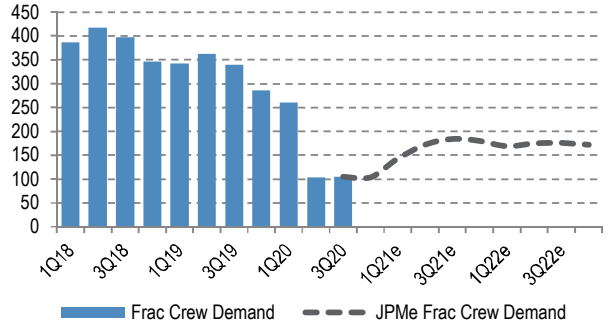
Source: EIA, Rystad, J.P. Morgan estimates.

Figure 138: Frac Spread Count (LHS) and Rig/Spread Ratio (RHS)



Source: Bloomberg Finance L.P., Primary Vision, Baker Hughes.

Figure 139: U.S. Frac Crew Demand



Source: Rystad, J.P. Morgan estimates.

After recent retirements and attrition, we see 12-12.5mm hp of useful capacity left in the frac market, with more shrinkage likely

Frac supply does not suggest a sufficiently tight market…yet

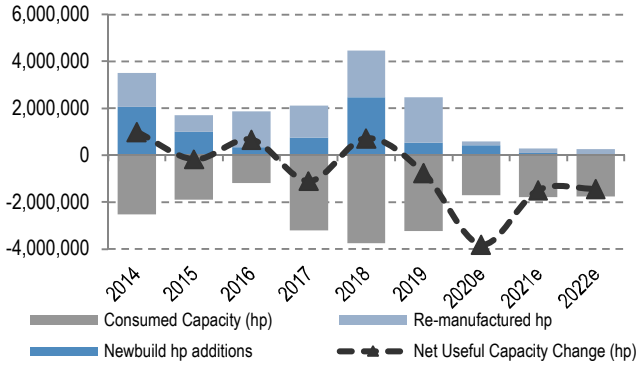
We have long called for more industry consolidation in NAM frac to create a healthier market structure, and with recent equipment reductions this may finally become (somewhat of) a reality. In 2020 we estimate that >5mm hp was retired or set aside for cannibalization. Notable examples include 1mm hp retired by SLB as part of the LBRT-OneStim tie up along with 1.25mm hp earmarked for maintenance use, 400k hp recently retired by NEX (which already got rid of some fleets as part of the FRAC-CJ merger), and ~1.5mm hp from BJ as part of its restructuring that we think is unlikely to go back to work.

With these reductions and accounting for normal attrition from wear and tear, we estimate that the useful capacity in the market is now 12-12.5mm hp. With newbuilds out of the picture except for one-off e-fleets, we expect this value to dip to 10-11mm hp in 2021 and 9-10mm hp in 2022. Of this capacity, we estimate that the frac "haves" (i.e. HAL, LBRT, NEX, PUMP) now possess approximately two-thirds of the useful hp in the market, a positive change for the providers given the market's fragmented history.

We see the potential for pumpers to request (and receive) some pricing gains as colder fleets are pulled back into service and upfront costs and minor capital outlays need to be covered, though the supply dynamic has a few key risks: 1) an improving market leads to less demonstrable attrition than we are currently modeling, 2) simul-frac adoption accelerates, allowing for phantom capacity creep, and/or 3) electric fleet demand pulls in fresh capital into the sector. Therefore we maintain a dash of caution with our optimistic bias for frac fundamentals into 2021.

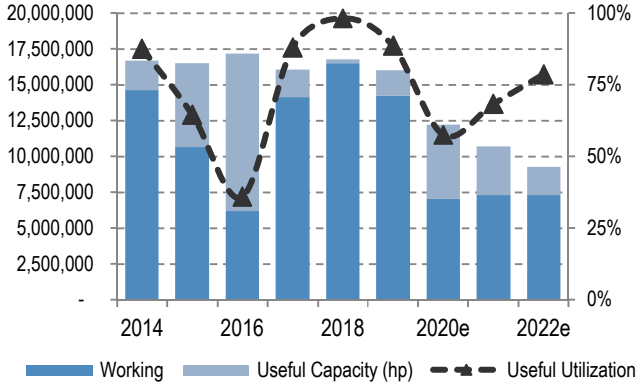
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 140: Useful HP Additions and Deletions



Source: Spears, Rystad, J.P. Morgan estimates.

Figure 141: Frac Useful HP Utilization

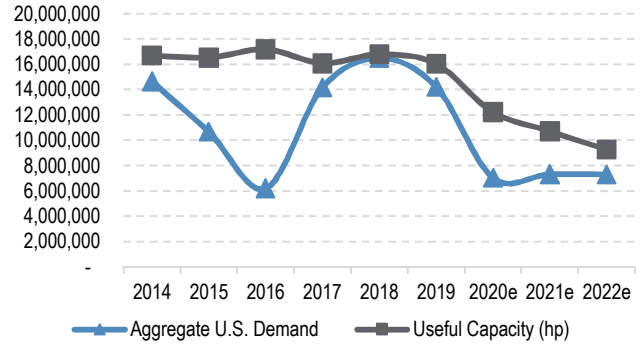


Source: Spears, Rystad, J.P. Morgan estimates.

Demand recovery to continue through 1H21, but 2H still up for debate

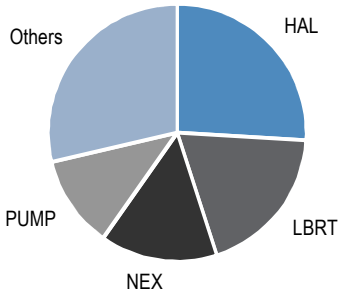
In 2021, we estimate demand for frac hp averaging ~7-7.5mm, meaning only about two-thirds of useful capacity will be utilized. This level will be insufficient on its own in our view to sufficiently tighten the market and hand the pumpers pricing power. More attrition will still be needed in 2021, potentially bringing useful utilization to 75-80% in 2022, near the >80% mark needed for improved unit economics. If E&Ps front-load their completions, there could be more at risk in 2H21, including the specter of another budget exhaustion season.

Figure 142: Frac Demand and Useful HP Capacity



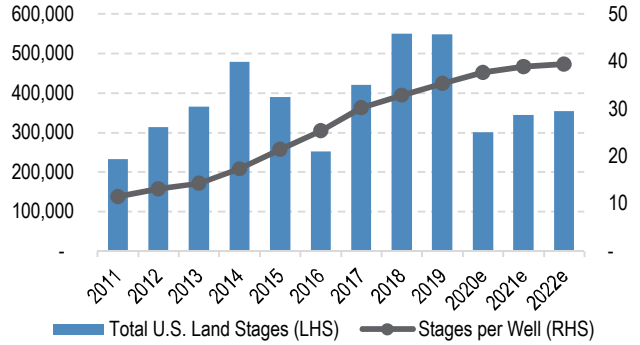
Source: Rystad, J.P. Morgan estimates.

Figure 143: Approx. Useful Capacity Allocation by Pumper



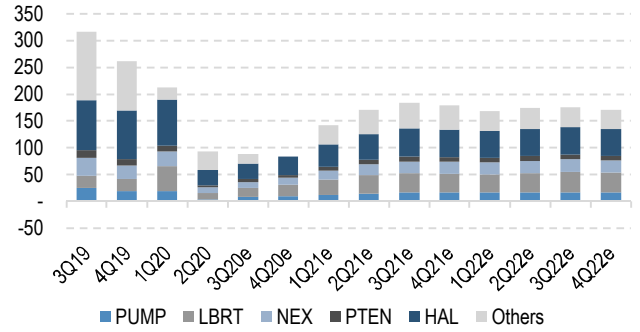
Source: Spears, Rystad, J.P. Morgan estimates.

Figure 144: U.S. Stage Count and Stages per Well



Source: Rystad, J.P. Morgan estimates.

Figure 145: Active Fleet Count by Pumper



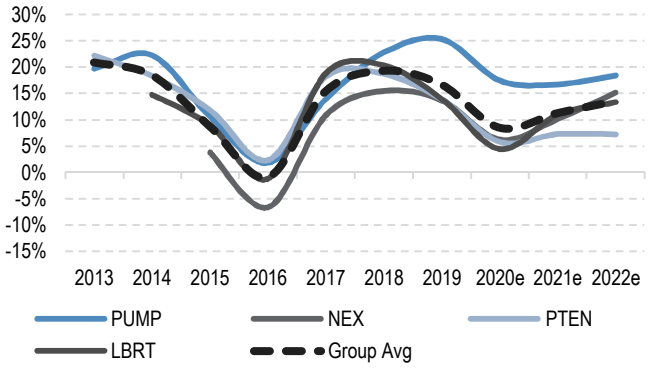
Source: Company Filings, Rystad, J.P. Morgan Estimates. LBRT is pro forma with OneStim.

Pricing remains trough-ish, look to operational leverage for margin support

Pricing for pressure pumping has been eroding for the past several years, and seems to have finally reached a bottom. Channel checks suggest that there are still some lower-quality pumpers bidding at "desperation" (i.e. FCF negative) levels in an attempt to secure utilization, but we expect such bidding to dissipate in 2021 as these competitors' crews are either squeezed from the market or put to work. While this may raise the bottom-end of pricing, we see only modest optimism for increasing average pricing among our coverage group early in 2021. During our Permian Tour a clear theme from E&Ps (as well as ProPetro) was that there is little reason to expect OFS cost inflation in 2021, though they aren't the first place to look for signs of coming OFS inflation.

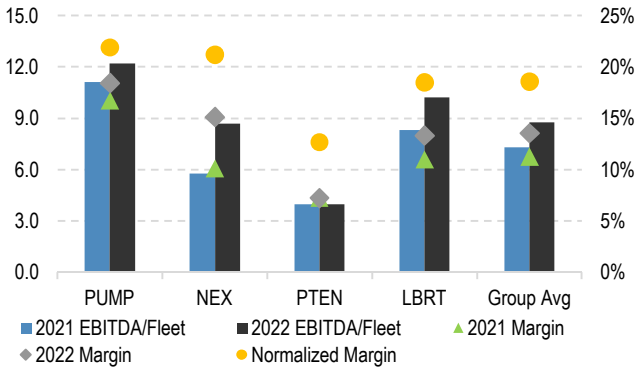
Given our caution on pricing progression, we think potential improvements to pumping profitability rest with the service providers themselves. After annualized EBITDA/fleet dipped into negative territory for LBRT and NEX in mid-2020 on anemic utilization, we think the pumpers can recover to MSD-HSD $mm annualized EBITDA/fleet in 2021 as more spreads go back to work and the companies can capitalize on operational leverage. PUMP was able to keep EBITDA/fleet positive through 2020 (troughing at ~$6mm/fleet), and given its lean operations we think the company can improve profitability further to a low-DD $mm annualized EBITDA/fleet in 2021.

Figure 146: Pressure Pumping EBITDA margins



Source: Company reports, J.P. Morgan Estimates. PTEN Pumping margins.

Figure 147: Frac EBITDA/Fleet ($mm, LHS) and EBITDA Margin (RHS)



Source: Company reports, J.P. Morgan estimates. *unadjusted for fluid ends capitalization

2022 profit metrics could approach our "normalized" assumptions

Looking out into 2022 we see additional upside to EBITDA/fleet across the group as utilization rates stabilize and operational efficiencies are realized. For NEX we think $8-9mm EBITDA/fleet is achievable, while for LBRT we model ~$10mm/fleet, and for PUMP we think incremental gains will be a little more modest and keep our expectation around ~$12mm/fleet. With this we see EBITDA margins for the group rising to the mid-teens in 2020 (from low-DD in 2021). On a normalized basis, we think the three pure-play pumpers can achieve EBITDA margins of ~20%, while Patterson's frac business is likely lower, in the 10-15% range.

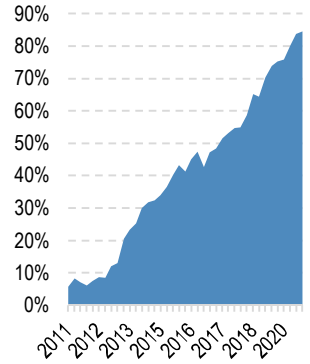
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

No Stop to Efficiency; Simul-frac to Drive More in 2021

Simul-frac finding more and more E&P fans; addressable market still TBD

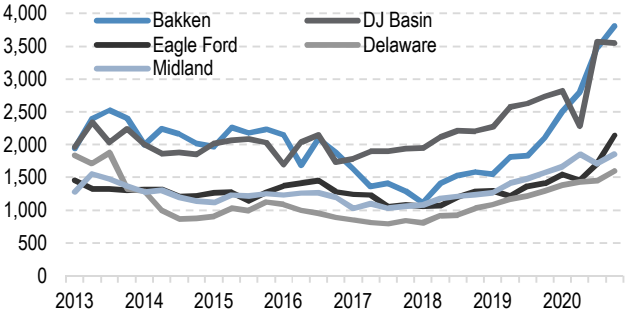
NAM pressure pumping has long been defined by a relentless push to squeeze more efficiency out of equipment, and we expect this trend to march on. Stages pumped per spread annually rose to 1,800-1,900 in 2020, up from <1,300 in 2014 as the mix of 24/7 operations increased and pumpers reduced downtime. 2020 saw notable upticks in lateral feet completed per day, including a +20-25% improvement y/y in the Permian and +25-30% in the Eagle Ford. Part of these gains are stem from increased zipper frac adoption, which now stands at ~85% of wells completed. Importantly, the share of simul-fracs within this group rose as well, to ~5% of zipper fracs in 2020 (~10% in November). Simul-frac presents a potential step change in efficiency, and generated buzz during our Permian Tour. We think further adoption can help drive lateral feet completed per day ~10% higher y/y in 2021. An important wrinkle to our assumptions however is that simul-fracs require less hp to complete (usually 60-70k hp from one fleet v. two 45k hp fleets for traditional zipper fracs), again undercutting demand for hp while delivering better results to customers.

Figure 148: Zipper Frac Mix



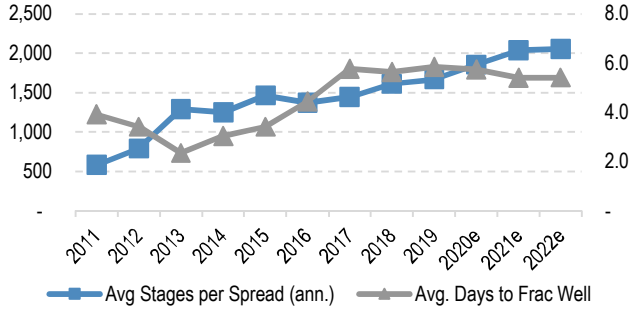
Source: Rystad.

Figure 149: Lateral Feet Completed per Day for Select Basins



Source: Rystad, J.P. Morgan estimates.

Figure 150: Annual Stages/Spread (LHS) and Days to Frac Well (RHS)

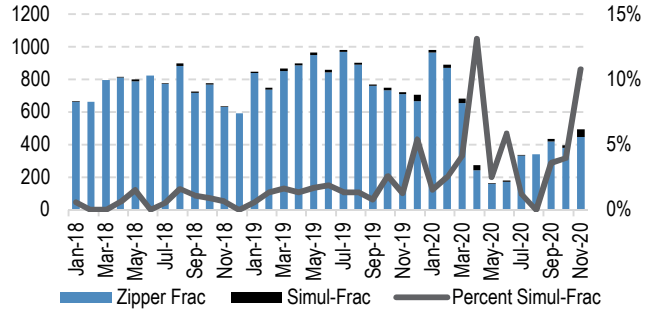


Source: Rystad, J.P. Morgan estimates.

ESG-driven solutions also on the rise, we see more dual-fuel than e-frac in 2021

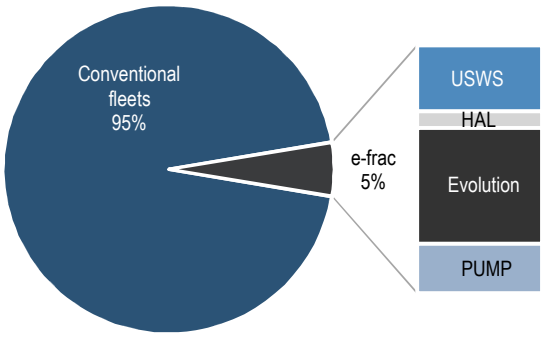
Another industry trend we are focused on in 2021 is the adoption of more ESG-friendly frac fleets. These fleets are in high demand as emissions considerations grow in importance among E&Ps, with ProPetro recently suggesting that industry dual-fuel and e-frac fleets are at full utilization. Near-term we think dual-fuel conversions are the most viable option for most pumpers given the industry-wide capital constraints and investor skepticism around e-frac investments. We estimate there are only ~15 e-frac fleets currently in the market, and believe that in order for pumpers to reward for investing in additional fleets, commitments from E&Ps to share in the costs will be needed, similar to what land drillers did 15-20 years ago with super-spec rigs.

Figure 151: Zipper and Simul-Frac Jobs and Simul-Frac Mix (RHS)



Source: Rystad.

Figure 152: : E-Frac Industry Allocation



Source: Company reports and J.P. Morgan estimates.

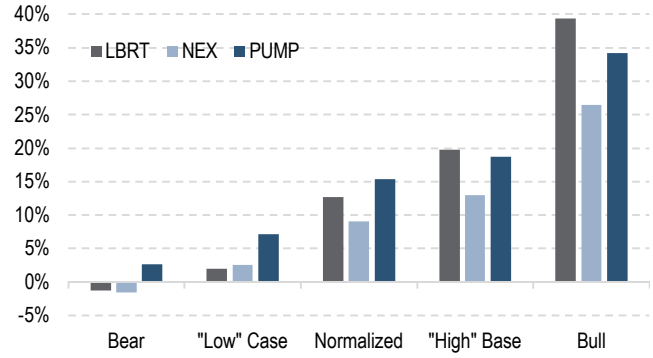
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Favor Cheap on "Normalized": OW NEX, PUMP; N LBRT

We see NAM pressure pumping as one of the fewer areas within our coverage where we think there is opportunity for investors to pursue "offense" instead of "defense". While our assumption for the U.S. fleet count to top out around ~180 in 2021 doesn't imply a super tight market (65-70% useful utilization), on a normalized basis we think the fleet count can average over 200 fleets. Following further attrition in the coming years, this sets up a better environment for pressure pumpers than in the prior cycle, especially for the frac "haves" that now control ~two-thirds of useful capacity and boast the best metrics by their crews.

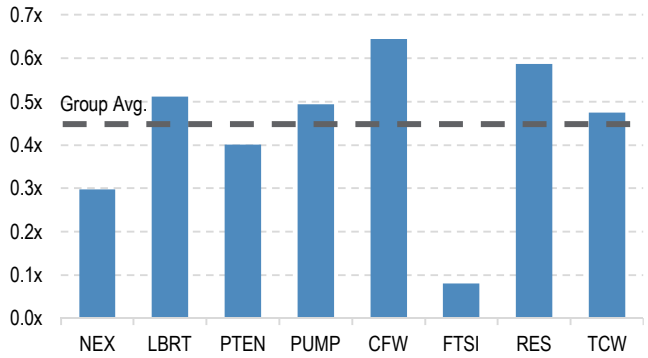
Though the market has shown a willingness to pull forward earnings expectations in NAM land, we see good upside optionality among the pressure pumpers and relatively compelling valuations. NEX perhaps stands out most, continuing to trade at a discount to peers on EV/replacement value basis (~0.3x v. ~0.5x for LBRT and PUMP). We think ProPetro could also earn more credit for better normalized results given our modeling of a ~15% FCF/EV yield. PUMP and NEX both fit our preference for clean balance sheets and strong operational track records as well, supporting our OW ratings. While we think LBRT is extremely well-run and at the vanguard of frac innovation, given the stock's strong performance (+1% YTD v. OSX -41%, frac peers -31%) we see better upside elsewhere, and remain Neutral.

Figure 153: Pressure Pumping FCF/EV Yield Estimates by Scenario



Source: Company reports, J.P. Morgan Estimates.

Figure 154: EV/Replacement Value



Source: Company reports, Bloomberg Finance L.P., J.P. Morgan estimates. *CFW, FTSI, RES, TCW based on BBG consensus.

Table 16: Frac Comp Sheet

Ticker	Rating	PT	Upside	Price	Div. Yield	2020e FCF Yield	2021e FCF Yield	Mkt Cap	EV	EV/EBITDA						Price/Book		HHP (000)	EV / Replacement (est.)
		$/sh	%	$/sh	%	%	%	$,bn	$,bn	2017	2018	2019	2020e	2021e	2022e	Curr	5-Yr Avg	4Q20e	
NEX	OW	$5	36%	$3.69	-	10%	-5%	0.8	0.9	1.3x	1.3x	1.9x	12.0x	7.1x	4.1x	1.3x	N/A	1,800	0.28x
LBRT	N	$10	(11%)	$11.24	-	-1%	-1%	1.3	1.2	5.6x	3.6x	5.6x	39.6x	5.6x	4.2x	2.5x	N/A	2,330	0.51x
PTEN	UW			$5.72	1.4%	17%	13%	1.1	1.8	3.2x	2.2x	3.0x	8.2x	13.4x	10.0x	0.5x	1.1x	1,300	0.41x
PUMP	OW	$6	(26%)	$8.10	-	14%	2%	0.8	0.8	5.6x	2.0x	1.5x	5.6x	4.9x	4.0x	0.9x	N/A	1,415	0.54x
CFW	NC			$0.24	-	-182%	-40%	0.0	0.9	4.7x	2.9x	5.8x	59.9x	15.4x	5.3x	N/A	0.9x	1,410	0.65x
FTSI	NC			$17.41	-	29%		0.2	0.1	2.7x	2.7x	2.7x	2.7x	2.7x	2.7x	N/A	N/A	1,400	0.08x
RES	NC			$3.74	-	-2%		0.8	0.7	1.6x	1.8x	5.4x	(53.1x)	34.4x	9.9x	1.3x	3.5x	728	0.57x
TCW	NC			$1.57	-	5%	5%	0.4	0.4	2.1x	4.9x	15.2x	21.3x	11.5x	6.0x	0.8x	0.8x	572	0.51x
Avg						-14%	-4%	0.7	0.8	3.3x	2.7x	5.1x	12.0x	11.9x	5.8x	1.2x	1.6x	1,368	0.44x

Source: Company reports and J.P. Morgan estimates. *CFW, FTSI, RES, TCW based on BBG consensus

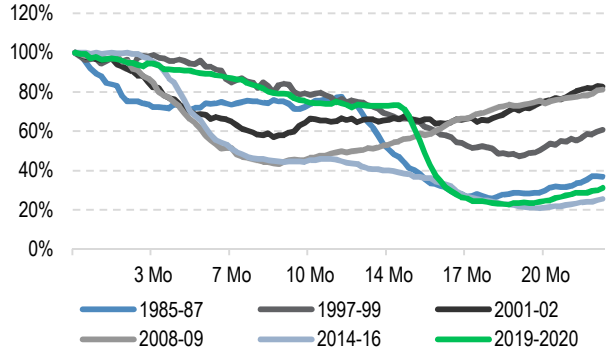
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Land Rigs: Activity to Reset Higher, Pricing to Lag

Historic U.S. rig reduction led by oil drilling now behind us

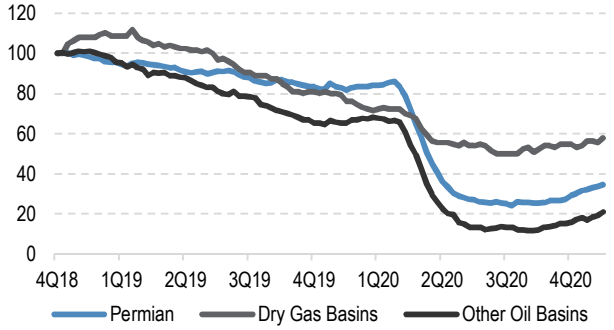
The L-48 witnessed the most severe drawdown in drilling activity in recent history in 2020, with the land rig count falling from 767 to 254 between the end of February and the end of June (-67%), before ultimately reaching a trough of 230 in mid-August. The decline was seen most acutely in the oil basins, with the Bakken down the most YTD (-79%), while the Permian fared the best among the oil basins (-59% YTD) due to its advantaged position at the forefront of U.S. activity. Meanwhile the gassier basins proved much more resilient, with the Haynesville falling only -18% YTD and the Marcellus/Utica -37% YTD, since demand for gas rigs was aided by some support from declining associated gas volumes from oiler-basins.

Figure 155: Lower-48 Rig Counts Post-Peak Activity Trends



Source: Baker Hughes and J.P. Morgan estimates.

Figure 156: Rig Count Change by Basin (Indexed to Dec-2018 Peak)

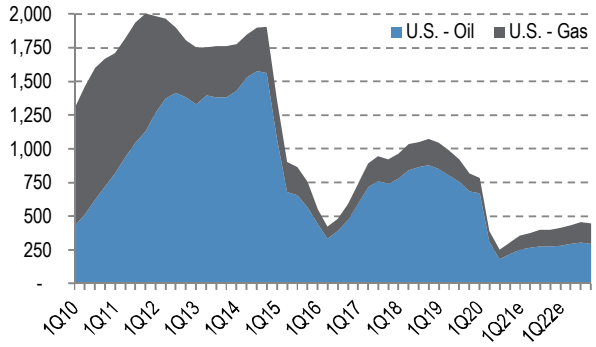


Source: Baker Hughes. Dry Gas Basins include the Haynesville and Marcellus / Utica.

We forecast the lower-48 rig count returning to 350-400 in 2H21

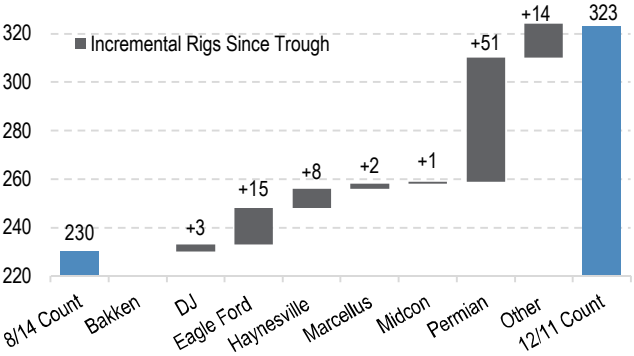
Heading into 2021, we estimate that the lower-48 rig count will need to return to the upper-300s in order to achieve broad E&P guidance to maintain crude production levels similar to 4Q20. The rig count has resurged by nearly +100 rigs since its mid-August low to a recent 323, but roughly two-thirds of these additions have come from private operators (see figure 160). To us, this suggests that many public E&Ps still have work to do in increasing drilling programs to hit 2021 production bogeys. As such we see continued upward bias to the rig count into mid-2021, by which point we expect most operators will be running at sustaining activity levels and the L-48 rig count should more or less tread water in 2H21 in the 350-400 range.

Figure 157: JPM U.S. Land Rig Count Forecast



Source: Baker Hughes and J.P. Morgan estimates.

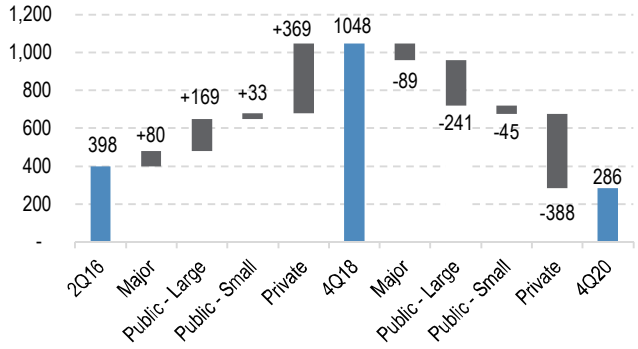
Figure 158: Incremental Rigs Added since the 8/14 Trough by Basin



Source: Baker Hughes.

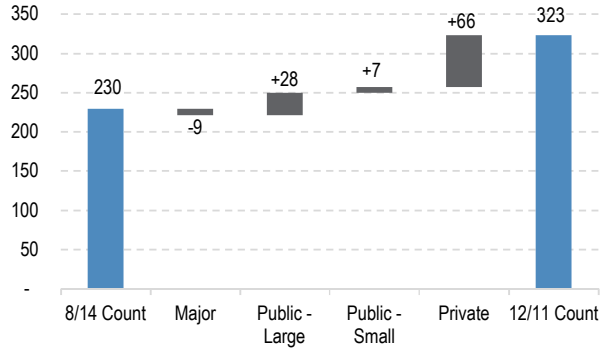
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 159: Trough to Peak to Trough Rig Change by Operator Type



Source: Baker Hughes, Enverus, J.P. Morgan estimates.

Figure 160: 2020 Trough to Present Rig Change by Operator Type

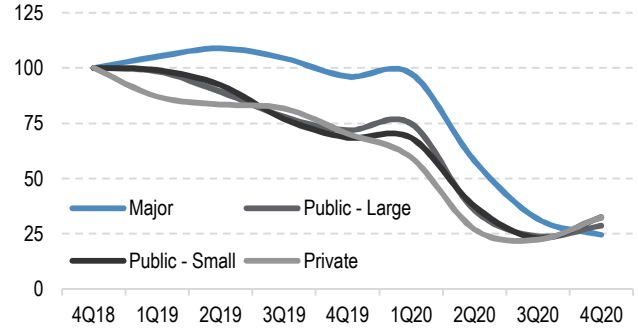


Source: Baker Hughes, Enverus, J.P. Morgan estimates.

Private E&Ps show agility in 2020, majors disappoint with drilling demand

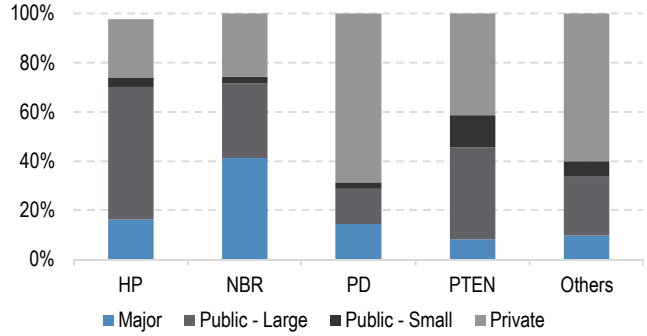
Among the operators, privates released the greatest number of rigs since the 4Q18 peak, but have also been at the leading-edge of rig additions in 4Q20, leaving the group -67% below its peak level. For the public E&Ps, the recent lag in participating the rig buildup of the past few months has left the group trailing the privates, with large public operators off -71% since the 4Q18 top, and small public E&Ps -67% lower. While the relative nimbleness of the private operators was consistent with our outlook, we were surprised to see how much the majors pulled back drilling activity in 2020, defying our expectations for these multinational operators to act as a ballast for L-48 demand. The rig count among the majors now stands -76% below 4Q18 levels, and the group has further removed rigs since August, counter to others.

Figure 161: Rig Count Change by Operator Type (Indexed to 4Q18)



Source: Baker Hughes, Enverus, J.P. Morgan estimates.

Figure 162: Big Four Exposures by Operator Type (TTM)



Source: Enverus, J.P. Morgan estimates.

Majors show preference for leading drillers; we see "torque" from public E&Ps

While the majors dropped a larger number of rigs than we anticipated in 2020, it appears that the group still followed our expectation to high-grade rig fleets. While the majors shed -75% of all rigs from 4Q19 to 4Q20, for H&P and Nabors only ~60% of rigs with majors were dropped. Meanwhile, for contractors outside of the "Big Four", -88% of rigs with the majors were released, representing a desire to consolidate providers and retain super-spec rigs. As such we still see the exposure to the majors as a relative benefit for HP and NBR. An outsized tilt to large-cap E&Ps gave H&P torque to the expanding rig count earlier in the cycle, but also a relatively higher "beta" to the declining rig count in 2020, leading to underperformance in utilization. Going forward, we think this beta will cut the other way as public E&Ps add more rigs, giving H&P good upside leverage in 2021 in our view. PTEN's rig count proved more resilient in 2020 than we feared, and we think its diversified customer base sets the company up to generally track the industry-wide rig count.

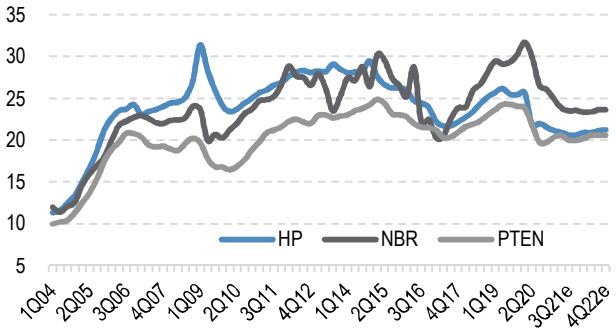
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Super-spec dayrates have fallen from low-to-mid $20k/d last cycle to high-teens $k/d currently; while we think spot rates can start to inch up in 2021, realized rates and margins likely remain under pressure

Average land rig pricing to reset lower in 2021 as longer-term contracts rollover

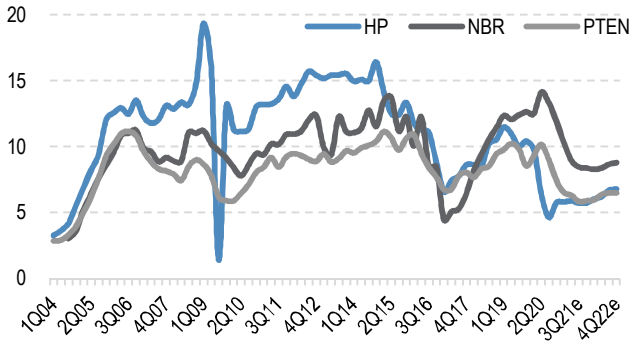
Land drilling dayrates and margins have been protected to some extent from falling demand in 2020 due to the longer-term nature of many contract agreements, keeping rigs operating at prices negotiated 1-3+ years ago. This sets up a scenario for declining rates and margins in 2021 in our view, as more rigs rollover to new, lower-priced contracts or go back to work on spot-based agreements. Leading-edge pricing for super-spec rigs has deteriorated from low-to-mid $20k/d in the last cycle to high-teens $k/d today. We think a transition to more contracts that are not based on dayrates but rather on KPIs will be vital to supporting drilling margins this cycle and giving the contractors the chance to capture value from their technology. Whether margin benefits from technology will prove durable through-cycle however is an open question, and we remain cautious. Each of the drillers has discussed such contracts, with HP the most vocal (see our Permian tour takeaways).

Figure 163: U.S. Onshore Rig Revenue Per Day (US$000)



Source: Baker Hughes, company reports and J.P. Morgan estimates.

Figure 164: U.S. Onshore Day Margins ($000)



Source: Company reports and J.P. Morgan estimates.

Technology is a battleground in land drilling, but adoption trending right way

Last year we argued that digital and automation technologies will be the next battleground for land drillers, and that looks all the more true following this year's downturn. We think operators are looking to contract only the highest performing rigs, reduce headcount at the wellsite, and extract the most production per dollar spent, setting up a good environment for further technology penetration. HP has seen adoption of its tech suite improve even with fewer rigs working, and has now drilled ~7mm commercial feet with AutoSlide. With that said, we think further adoption will take time, and caution that initial benefits could ultimately be competed away.

Table 17: Select Drilling Technology Offerings by Driller

HP	NBR
• MOTIVE: Bit guidance system • MagVAR: In-Field Referencing (IFR) system which creates models of geomagnetic fields • AutoSlide: leverages several FlexApps and includes the Motive Bit Guidance system to automate much of the horizontal drilling process	• SmartROS: Rig operating system for machine and process automation apps • SmartSLIDE: Automated directional steering control system • SmartNAV: Directional guidance platform; generates automated steering instruction
PD	**PTEN**
• NOVOS (from NOV) • AlphaAutomation: integrated automation of repetitive drilling activities • AlphaApps: open software platform optimizing complex drilling tasks • AlphaAnalytics: real time data analytics system	• CORTEX: Proprietary OS for APEX rigs through which various control applications are run • Superior QC: Bit guidance system • MS Directional: directional drilling services, including downhole motors, MWD, and steering tools

Source: Company reports.

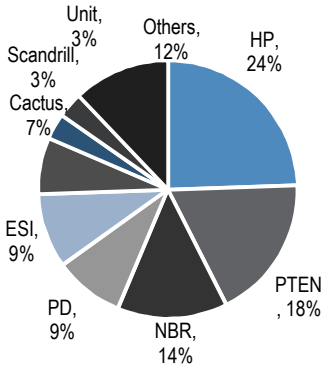
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Favor Upside "Torque": N HP, UW PTEN, NBR

We see the continued high-grading of operator fleets going forward as a benefit to the drillers in our coverage, which possess ~80% of the super-spec rigs in the market and the most advanced drilling technology solutions. With many operators seeking to consolidate service providers, we expect to see the market share of HP, NBR, and PTEN grow from ~60% in 2020 towards ~70% by 2022. Among the group we think H&P's high "torque" to the growing L-48 market gives it the best upside optionality, and we like the company's strong balance sheet and robust technology suite.

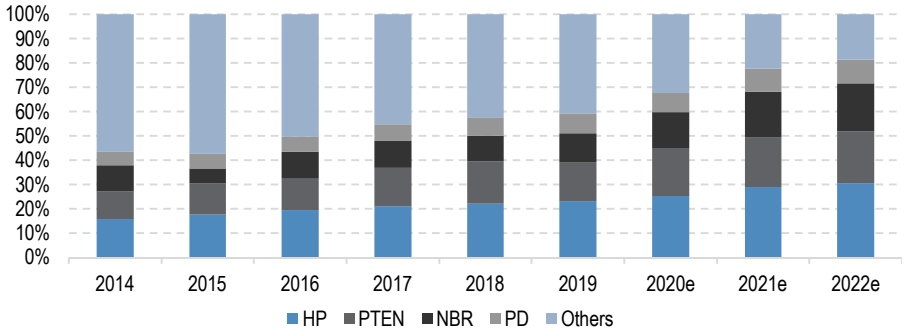
Meanwhile we think Patterson's relatively more stable rig utilization and orientation to the gas basins will limit its participation as E&Ps put more rigs to work compared to HP, and we see the company's lower-quality pumping business as disadvantaged going forward. For Nabors, we continue to see the debt burden as a major overhang for equity investors (even after balance sheet management measures were taken in 2020) given our outlook for the company's FCF generation capacity this cycle, and we recommend investors avoid the stock. As such, HP remains our preferred relative name among the group (though we downgrade our rating on the shares to Neutral on recent share price strength well above our Dec-2021 price target), and we maintain our Underweight ratings for PTEN and NBR.

Figure 165: L-48 Market Share (2020e)



Source: Enverus, Baker Hughes, J.P. Morgan Estimates.

Figure 166: L-48 Land Drilling Market Share: We Expect Further Gains among Our Coverage



Source: Company Reports, Baker Hughes, J.P. Morgan Estimates.

Table 18: JPM Rig Count Forecasts - Summary

													Y/Y Change				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020e	2021e	2022e	2018	2019	2020e	2021e	2022e
U.S. - Oil	982	1,359	1,373	1,525	746	409	703	841	774	344	268	293	20%	-8%	-56%	-22%	9%
U.S. - Gas	886	556	383	332	226	100	172	190	169	88	115	144	10%	-11%	-48%	30%	26%
U.S. Offshore	32	47	56	57	35	23	20	19	23	15	17	20	-7%	22%	-33%	9%	18%
U.S. Total	**1,875**	**1,919**	**1,761**	**1,860**	**974**	**510**	**876**	**1,032**	**943**	**434**	**382**	**437**	**18%**	**-9%**	**-54%**	**-12%**	**14%**
Canada Oil	284	262	233	215	87	63	110	120	83	47	29	29	9%	-31%	-44%	-38%	0%
Canada Gas	140	102	120	161	108	67	96	71	51	42	38	38	-26%	-29%	-16%	-10%	0%
Canada Total	**424**	**363**	**353**	**376**	**194**	**130**	**207**	**191**	**134**	**89**	**67**	**67**	**-8%**	**-30%**	**-33%**	**-25%**	**0%**
NAM Total	**2,299**	**2,282**	**2,114**	**2,236**	**1,168**	**640**	**1,083**	**1,223**	**1,077**	**523**	**450**	**504**	**13%**	**-12%**	**-51%**	**-14%**	**12%**

Source: Baker Hughes and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

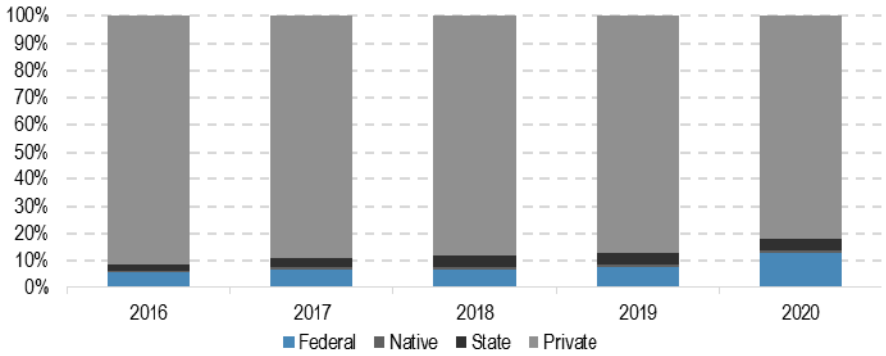
Biden Administration Eyes New Federal O&G Regulations

With lack of "blue wave", we see limited impact to OFS from new regulations

Heading in to the 2020 U.S. presidential election we highlighted potential tail risks to U.S. shale activity should the Democrats win the White House and gain ground in Congress in a "blue wave". While this did not materialize, the Senate could still flip to Democratic control pending the results of the 1/5 Georgia runoff elections. We think president-elect Biden and his administration will move to implement new restrictions on drilling (and more directly fracking) on federal lands through executive action and hinder some O&G development through the EPA, but if the GOP retains control of the Senate we see the extent of possible regulations as fairly limited. With only ~10% of frac activity taking place on federal land, the actions of the Biden administration alone should only have modest effects on overall U.S. production since activity can be shifted to state/private property. As such we view a split Congress as the most favorable outcome for OFS, and believe the market is pricing in a fairly high probability of this result, driving a constructive "gridlock trade" for NAM stocks.

Should the Democrats win the two seats in Georgia and claim a delicate majority in Senate (with VP-elect Kamala Harris able to cast a tie-breaking vote in a 50/50 split), we think the scope of possible regulations expands. Still, many of the Democrats' more ambitious energy proposals are unlikely to pass with such a slim Senate majority, in our view. In addition, on our recent Permian Tour several operators discussed measures that can be taken to push back against expanding regulations, including legal action to defend rights to undrilled leaseholds, and suggested that the Governor of New Mexico may request a waiver for restrictions on federal land in the state given NM receives ~40% of its income from the oil and gas industry through tax payments. Even with a 50/50 Senate split, we see regulatory risks to services as relatively modest going forward.

Figure 167: U.S. Federal Land Frac Activity: Growing but Still a Minority Share

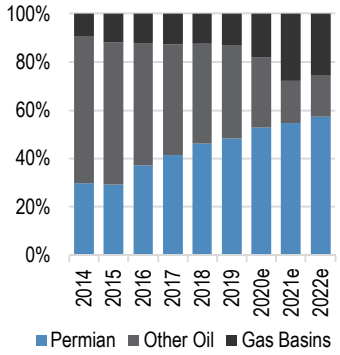


Source: Rystad.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Permian: The Premier U.S. Oil Basin to Lead 2021 Rebound

Figure 168: L-48 Rig Mix by Basins

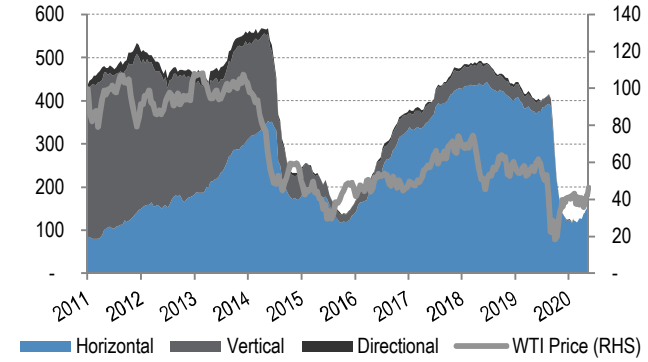


Source: Baker Hughes, J.P. Morgan Estimates.

The Permian's rig count has been relatively more stable than other oil basins in 2020, with its current count down -59% YTD (v. -68% for other oil basins, -28% for gassier basins). Similarly, Permian frac activity proved more resilient than in other basins, with the latest Permian frac spread count standing -42% lower YTD v. -85% in other oil basins. We expect the Permian to be the driving force for L-48 activity growth in 2021 (and beyond), and expect the basin to further expand its share of active land rigs to 55-60% in 2021/2022 (v. ~53% in 2020). We see this dynamic already playing out in 2H20; since the mid-August rig count trough, the Permian has claimed more than half (+51) of the incremental rigs put back to work (+93 total).

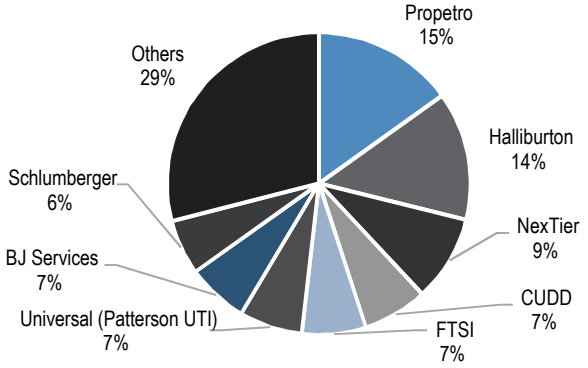
Among our coverage group, all of the land drillers have large positions in the Permian, with TTM averages ranging from nearly 60% exposure for HP to 33% exposure for PTEN. As activity declines elsewhere though, we expect this mix to tilt more towards the Permian, such as with Patterson's most recent Permian exposure climbing to 45-50% of its active rigs. For the pressure pumpers, we like PUMP's Permian-only focus and strong relationships with blue-chip operators in the basin. On our recent Permian tour, ProPetro expressed cautious optimism for increasing frac activity in the Permian early next year, and sees operator interest in more simul-frac work and in e-frac fleets. For the rest of our coverage, HAL and NexTier both have prominent footprints in the Permian, and LBRT is set to further expand its exposure following the acquisition of OneStim.

Figure 169: Permian Rig Count by Type v. WTI Price



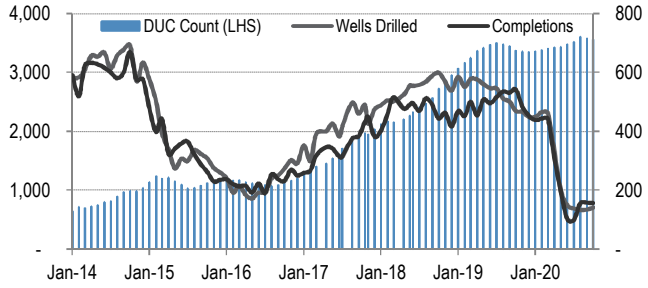
Source: Baker Hughes, Bloomberg Finance L.P.

Figure 170: Permian Frac Demand by Pumper (TTM)



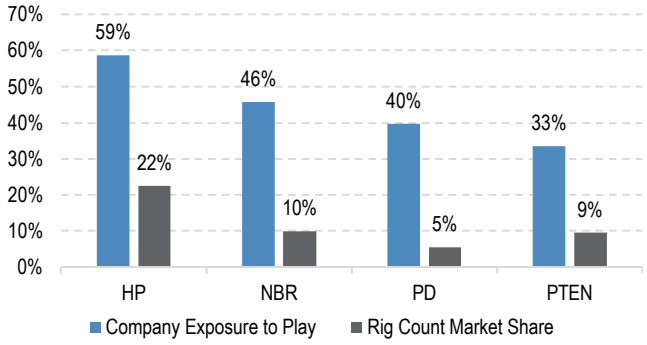
Source: Rystad.

Figure 171: Monthly Wells Drilled/Completed and DUC Inventory



Source: EIA.

Figure 172: Permian Contract Driller Market Share, Exposure (TTM)



Source: Enverus.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

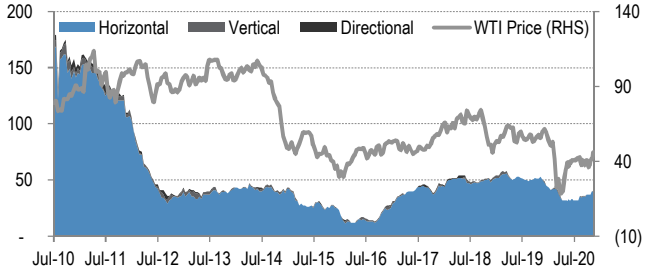
Gas Basins: Haynesville and Marcellus/Utica Look Relatively Stable, but at the Expense of Upside

The rig count in the Haynesville is down only -18% YTD and the Marcellus/Utica count is -37% lower YTD, outperforming the L-48 average of -58% YTD

OFS activity in the gas basin activity trended much differently than the oil basins in 2020, with the Haynesville rig count now down only -18% YTD and the Marcellus/Utica rig count down -37%, demonstrating more resiliency than the overall L-48 rig count (-58% YTD). Declining associated gas volumes for liquids-focused basins and a relatively more stable demand environment for gas lent support to gas drilling activity. On the completions side, we see a similar picture, with frac spreads in gas basins currently -41% lower than at the beginning of 2020, showing better utilization than the overall L-48 (-57% YTD). Heading into 2021, we think the gas basins will grow off current levels and again exhibit relative resilience, but that also means we anticipate less potential upside to OFS demand in the regions.

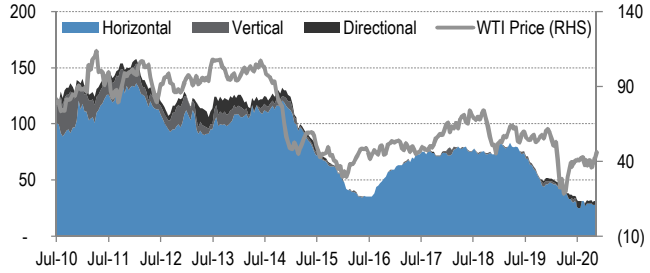
Across our coverage, PTEN has been the dominant driller in the Northeast over the past 12 months, with ~20% of its active rigs operating there, giving it ~35% market share. Patterson also has the largest allocation to the Haynesville among the drillers, with ~10% exposure. These regions were a boon to PTEN's rig utilization in 2020, which outperformed our expectations, and have grown in importance as activity fell of elsewhere (recently PTEN has had ~25% of its rigs in the Northeast and ~15% in the Haynesville). Among the pumpers in our coverage, HAL, NEX, and PTEN all have sizable allocations to the Marcellus/Utica, while HAL has ~25% market share in the Haynesville followed by SLB, which is about to become part of LBRT after the OneStim deal closes. This represents an important foray for Liberty into gas-focused work that we think will help diversify its operations.

Figure 173: Haynesville Rig Count by Type v. WTI Price



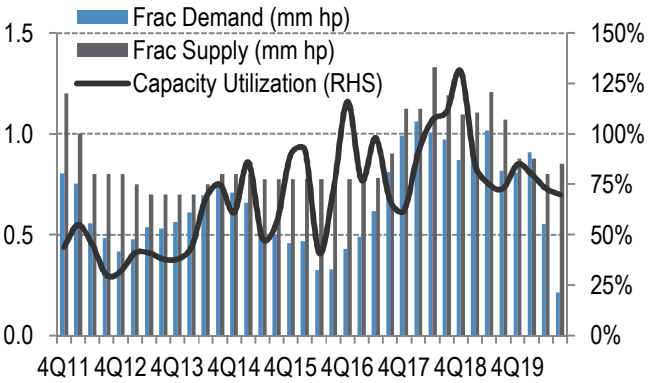
Source: Baker Hughes, Bloomberg Finance L.P.

Figure 174: Marcellus/Utica Rig Count by Type v. WTI Price



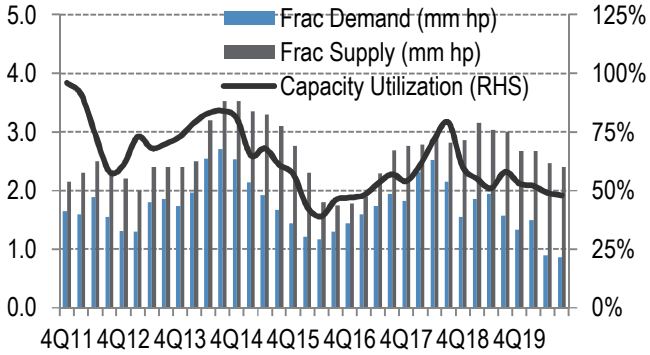
Source: Baker Hughes, Bloomberg Finance L.P.

Figure 175: Haynesville Frac Supply/Demand and Utilization



Source: Rystad.

Figure 176: Marcellus/Utica Frac Supply/Demand and Utilization

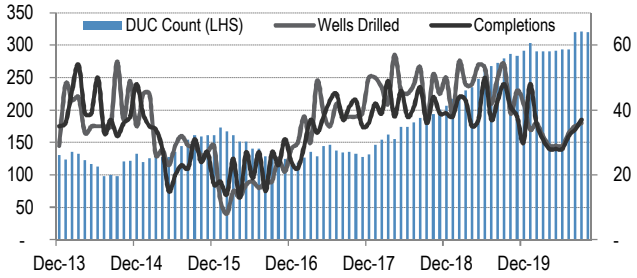


Source: Rystad.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

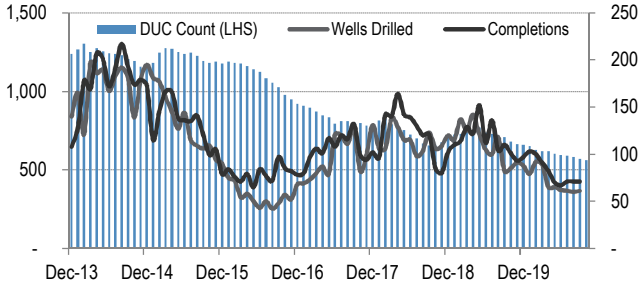
Gas basins by the numbers

Figure 177: Haynesville Wells Drilled/Completed and DUC Inventory



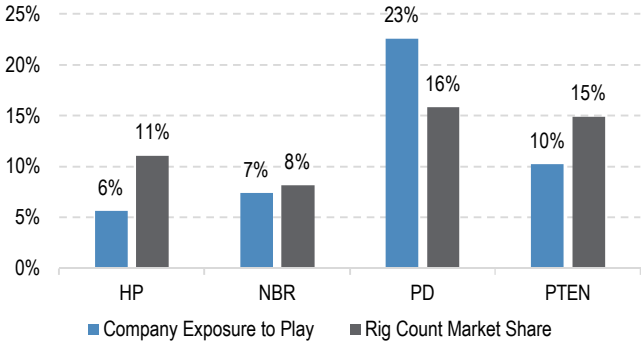
Source: EIA.

Figure 178: Marcellus/Utica Wells Drilled/Completed, DUC Inventory



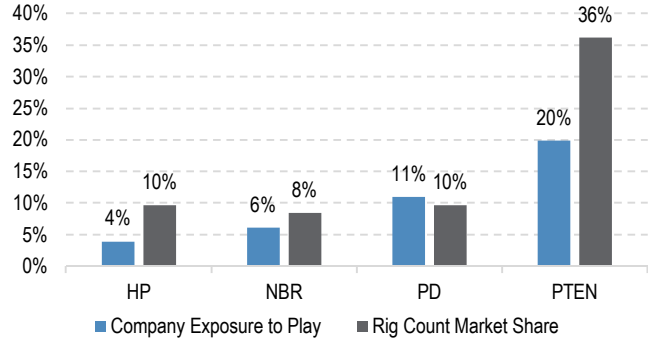
Source: EIA.

Figure 179: Haynesville Contract Driller Market Share, Exposure (TTM)



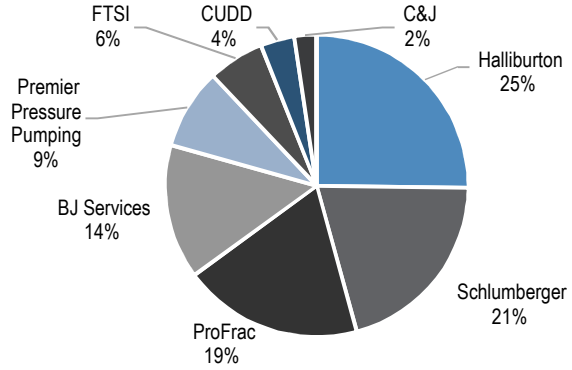
Source: Enverus.

Figure 180: Marcellus/Utica Driller Market Share, Exposure (TTM)



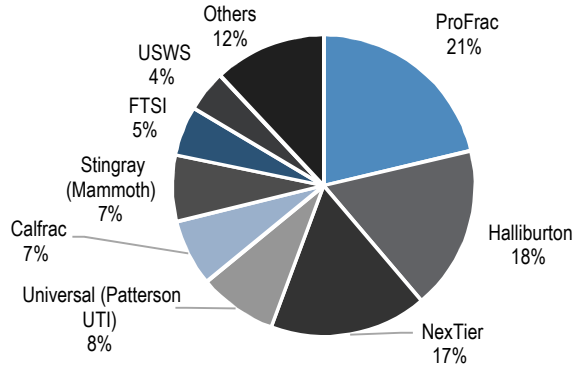
Source: Enverus.

Figure 181: Haynesville Frac Demand by Pumper (TTM)



Source: Rystad.

Figure 182: Marcellus/Utica Frac Demand by Pumper (TTM)



Source: Rystad.

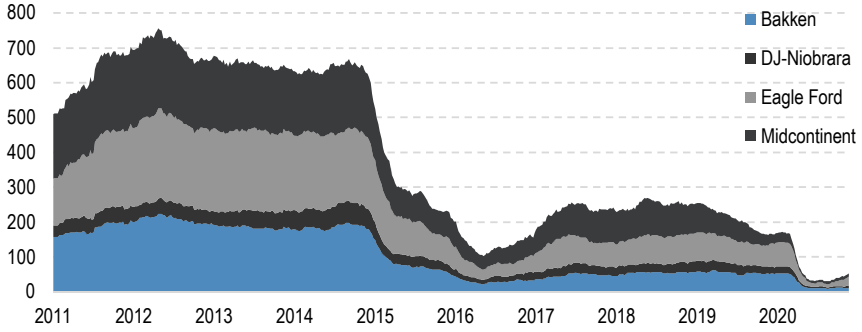
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Other Oil Basins: Modest Upside While Trailing the Permian

Among other core U.S. oil basins, we favor the Eagle Ford, while keeping a more bearish view on the Midcontinent

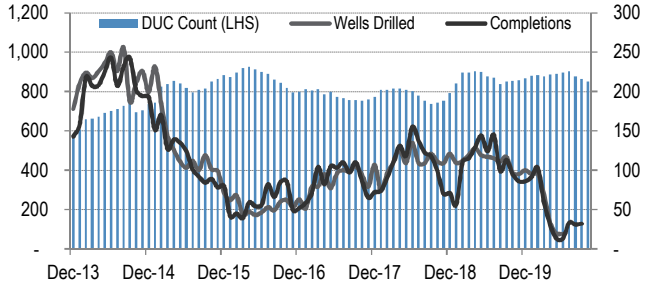
Core U.S. oil basins outside of the Permian (Bakken, DJ, Eagle Ford, and Midcontinent) suffered the worst hits to OFS utilization in 2020. For the group, the average rig count is now -68% lower YTD (v. L-48 and Permian -59%, gas basins -28%), led by the Bakken (-79% YTD). The picture is even bleaker for pressure pumping, where the fleet count in these basins now stands -85% lower YTD (v. L-48 -57%). Going forward we expect activity within these basins to continue to be relatively disadvantaged v. the Permian and gassier basins, but not uniformly. The Eagle is likely the most advantaged in our view, after demonstrating a solid recovery recently, rising to a current rig count of 26 after hitting a bottom of <10 in 3Q20. For the drillers, HP and PTEN have exposures >10% to the Eagle Ford, and for the pumpers, HAL, PTEN, and SLB (soon to be LBRT) have leading positions in the basin. Conversely, we think the Midcontinent is likely the most disadvantaged basin among the group in 2021, and we expect the rig count there to struggle to move much beyond its recent HSD average. H&P and Patterson have the largest positions in the Midcontinent for drillers, while HAL and SLB (i.e. LBRT) lead for pumpers.

Figure 183: Rig Count of Other Oil Basins



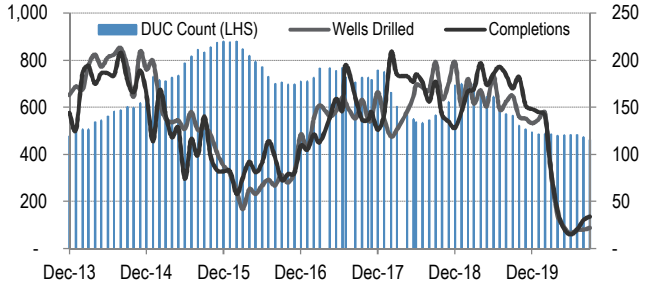
Source: Baker Hughes.

Figure 184: Bakken Wells Drilled/Completed and DUC Inventory



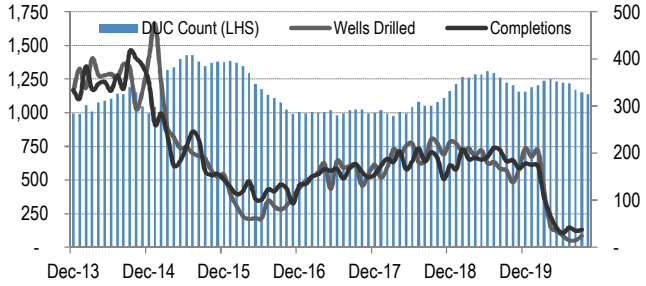
Source: EIA.

Figure 185: DJ-Niobrara Wells Drilled/Completed and DUC Inventory



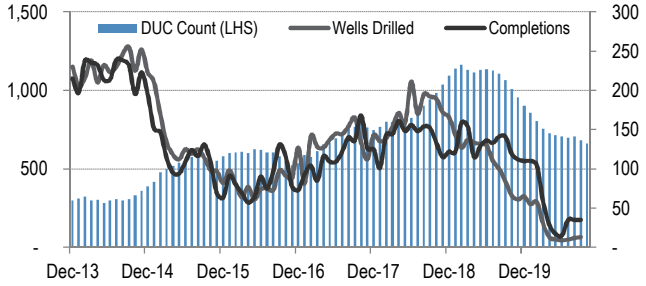
Source: EIA.

Figure 186: Eagle Ford Wells Drilled/Completed and DUC Inventory



Source: EIA.

Figure 187: Midcon Wells Drilled/Completed and DUC Inventory

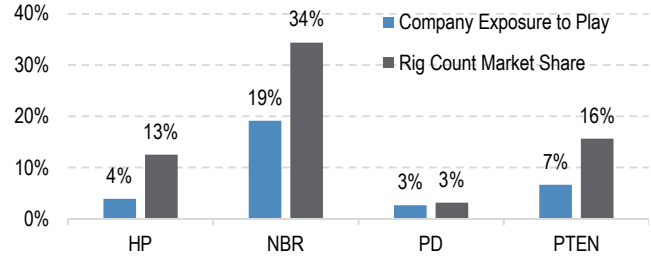


Source: EIA.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

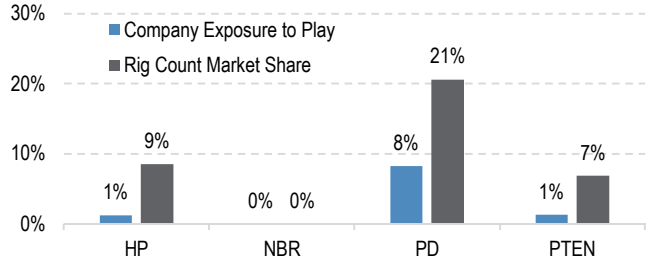
Other oil basins by the numbers

Figure 188: Bakken Contract Driller Market Share, Exposure (TTM)



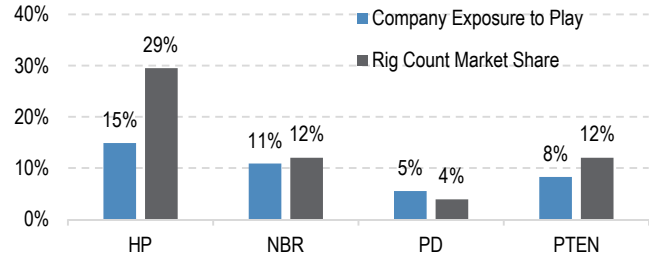
Source: Enverus.

Figure 189: DJ-Niobrara Driller Market Share, Exposure (TTM)



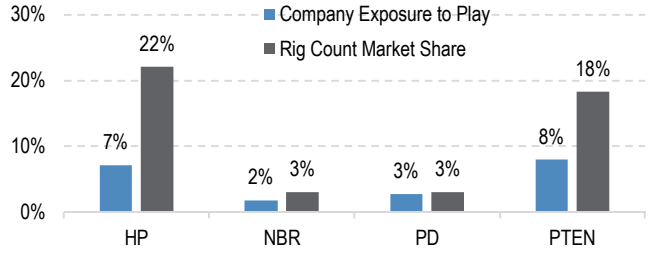
Source: Enverus.

Figure 190: Eagle Ford Contract Driller Market Share, Exposure (TTM)



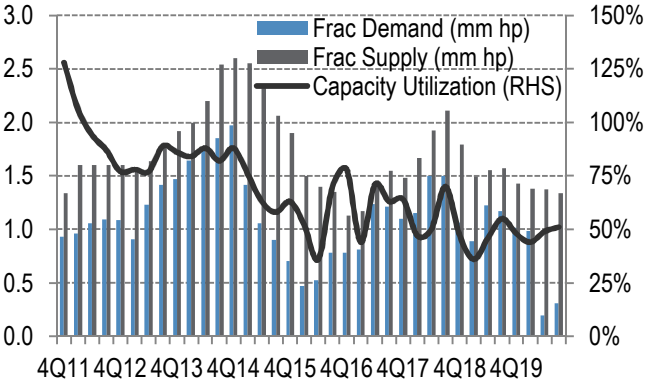
Source: Enverus.

Figure 191: Midcon Contract Driller Market Share, Exposure (TTM)



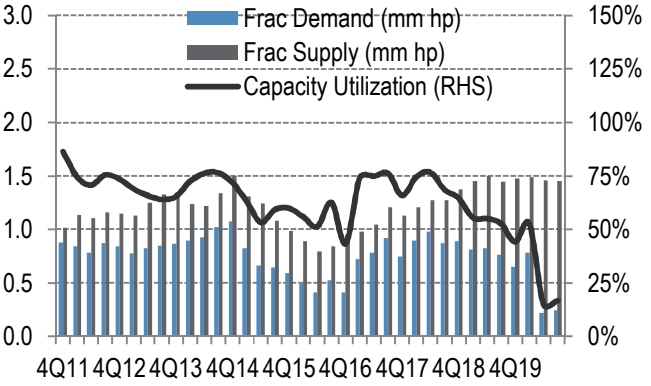
Source: Enverus.

Figure 192: Bakken Frac Supply/Demand and Utilization



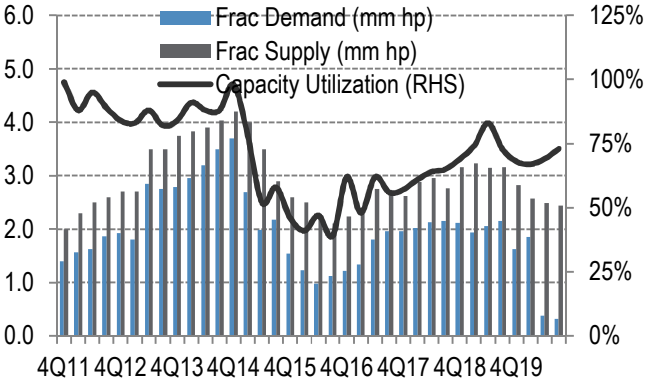
Source: Rystad.

Figure 193: DJ-Niobrara Frac Supply/Demand and Utilization



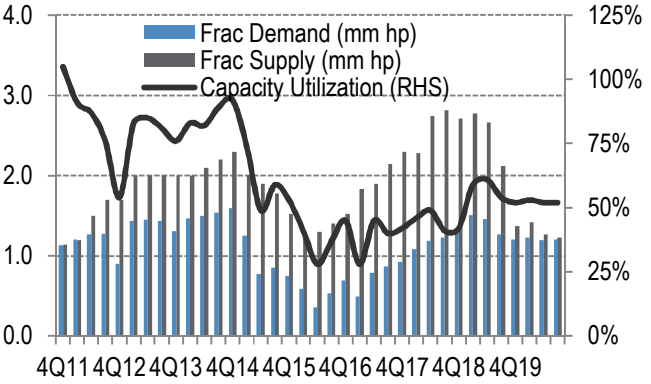
Source: Rystad.

Figure 194: Eagle Ford Frac Supply/Demand and Utilization



Source: Rystad.

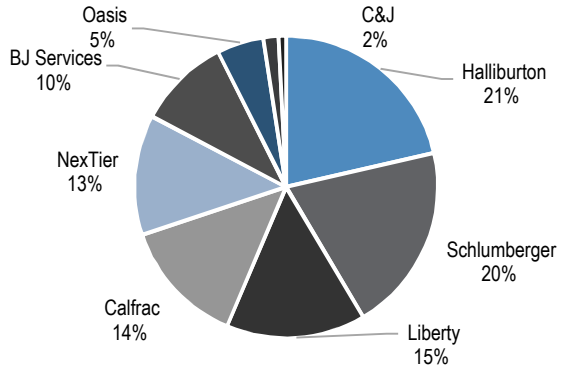
Figure 195: Midcon Frac Supply/Demand and Utilization



Source: Rystad.

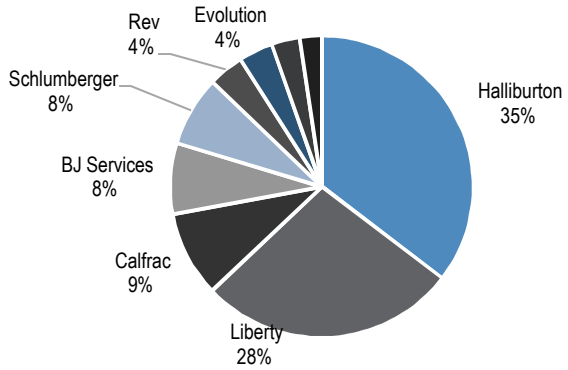
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 196: Bakken Frac Demand by Pumper (TTM)



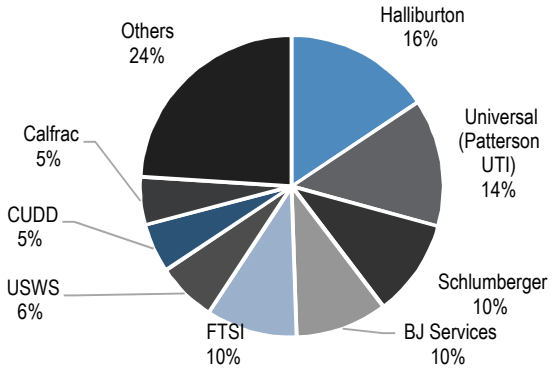
Source: Rystad.

Figure 197: DJ-Niobrara Frac Demand by Pumper (TTM)



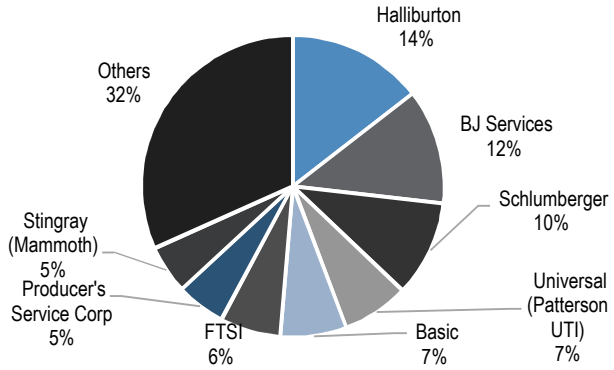
Source: Rystad.

Figure 198: Eagle Ford Frac Demand by Pumper (TTM)



Source: Rystad.

Figure 199: Midcon Frac Demand by Pumper (TTM)



Source: Rystad.

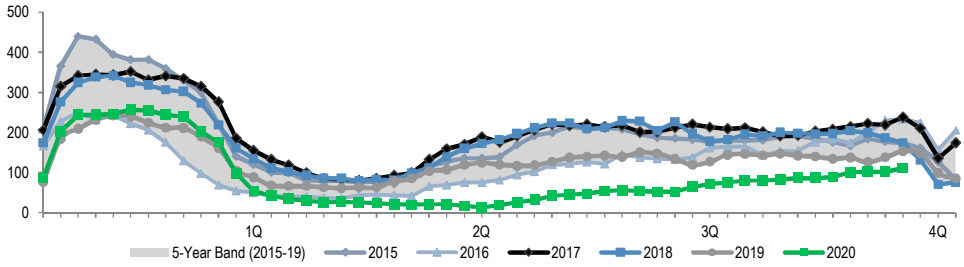
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Canada: Moving Past Worst y/y Drops, but Remains Tough

After the Canadian rig count fell -30% y/y in 2019 (v. L-48 -9% y/y), the count took an even bigger hit in 2020, averaging -41% lower y/y to date. 2Q20 was exceptionally bad north of the border as the seasonal spring slowdown was compounded by plunging crude demand, sending the rig count -70% lower y/y. Activity has since improved, especially for gas drilling, but 4Q20 is still tracking -36% below 4Q19 levels.

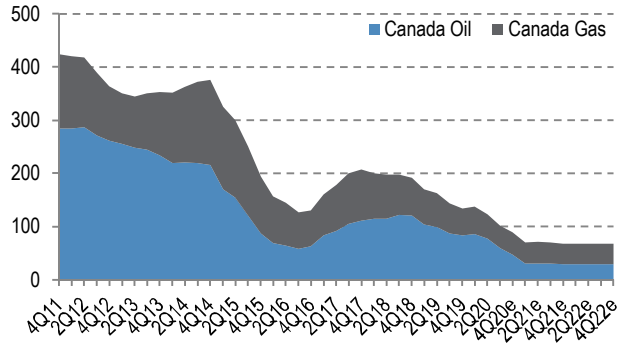
Going forward, we expect to see the Canadian rig count move directionally higher into 1Q21 with the normal seasonal uptrend, though we believe it will still remain -35-40% below the corresponding period last year. After that, we anticipate that 2Q21 activity will fare about +15-20% better y/y as the macro backdrop will (presumably) be less extreme than in the spring of 2020. However we think Canadian OFS demand remains structurally challenged, and see rig count growth as flat-to-down y/y in 2H21 and beyond.

Figure 200: Canada Onshore Rig Count by Year



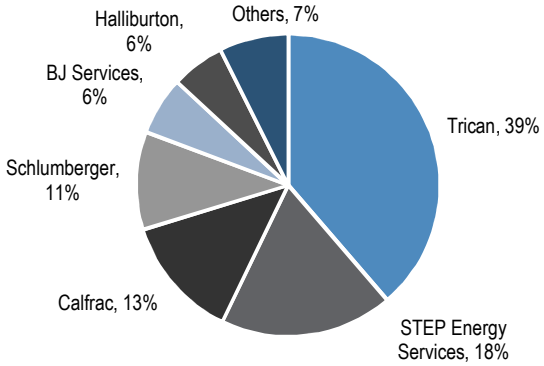
Source: Baker Hughes

Figure 201: Canada Rig Count Forecast (TTM average)



Source: Baker Hughes.

Figure 202: Canada Pressure Pumping Market Share (TTM)



Source: Rystad.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

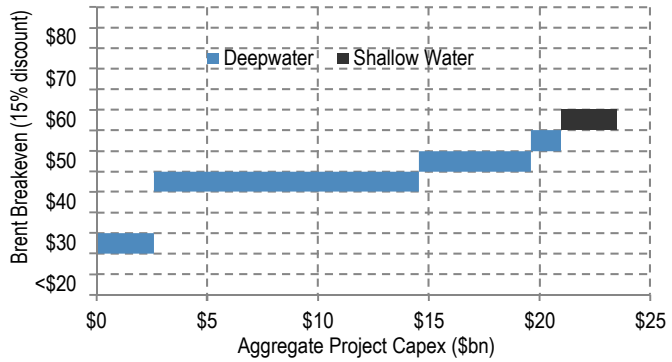
U.S. Gulf of Mexico: Slow and Sluggish Recovery in the Works; Drilling Remains Disadvantaged v. Subsea

Depleted driller backlogs and dim demand keep the pursuit for utilization alive with more supply rationalization needed

Investment likely bottomed in 2020 but appetite to ramp next year looks limited

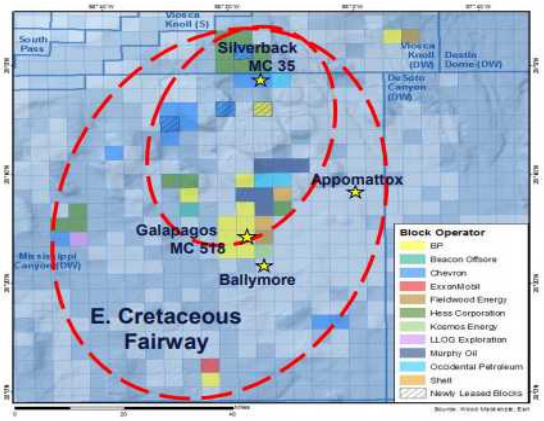
Annual investment in the U.S. GOM has fallen to ~$6bn, levels not seen since 2010 with ~$4.5bn in spend deferred, per WoodMac. Any significant rebound is dependent on the large projects yet to be sanctioned: Shenandoah/Whale (2021), North Platte/Moccasin/Leon (2022) and Ballymore (2023). Shenandoah seems to be on the cusp of FID (with below a $30/bbl breakeven and the *Deepwater Atlas* contracted) while the timelines of the others remain more at risk with ~$45/bbl breakevens (at 15% IRR) and operators facing investor pressure to delay/cancel wherever possible. 2020 was slow for M&A, pushing potential to 2021 but regulations remain a risk.

Figure 203: U.S. GOM pre-FID Cost Curve Through 2023…



Source: Wood Mackenzie, J.P. Morgan estimates.

Figure 204: …Cretaceous Seen as Next (Eventual) Area of Growth



Source: Wood Mackenzie.

Offshore drilling spend to be flattish through 2022

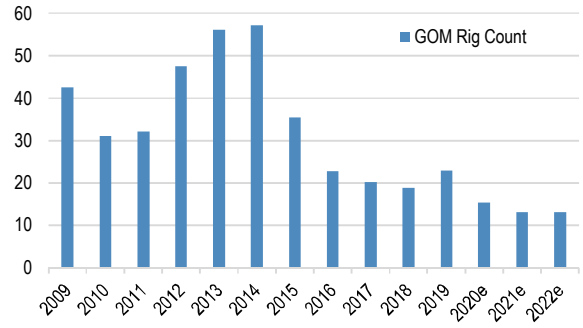
In shallow water, jackup contracting looks to remain quiet after largely being held to 1-3 month fixtures. IHS thinks three 1-well tenders are probable next year (25-50% chance). Just as the region's drillship market was starting to (somewhat) tighten and see +$220k/day, the pandemic hit, bringing recent fixtures back closer to breakeven (e.g. *Pacific Sharav/West Vela* at $180k/$200k per day). Of course, the 20k capable *Atlas* inked a contract at ~$455k/day with Beacon. Given the oversupply of drillships (3 warm and 3 rolling off mid-2021) with weak (and short term) demand, we expect less than $200k/day in 2021 with limited upside in 2022. The semi market remains weak with only one contracted into 2021 with three of the ~six cold (slight positive).

Figure 205: Notable "Probable" Tenders in the U.S. GOM

Operator	Status	Rig Type	Description	Start Date	Duration Range	
Walter	Probable	Semi	Up to 5 wells	Jan-21	150	300
Walter	Probable	Semi	1 well	Jan-21	180	380
EnVen	Probable	Drillship	2 wells	Mar-21	180	180
Kosmos	Probable	Semi	3 wells	Apr-21	270	270
GulfSlope	Probable	Jackup	1 well	Apr-21	140	140
LLOG	Probable	Drillship	Up to 2 wells	Apr-21	90	360
Talos	Probable	Drillship	1 well	Apr-21	60	60
Murphy	Probable	Drillship	Up to 4 wells	Jun-21	90	90
Equinor	Probable	Drillship	1 well	Jul-21	120	120
LLOG	Probable	Drillship	2 wells	Aug-21	45	90
Talos	Probable	Drillship	3 wells	Sep-21	105	270
Total	Probable	Drillship	8 wells + options	Apr-22	1460	1,825

Source: IHS-Petrodata, J.P. Morgan estimates.

Figure 206: U.S. GOM Rig Count



Source: Baker Hughes, J.P. Morgan estimates.

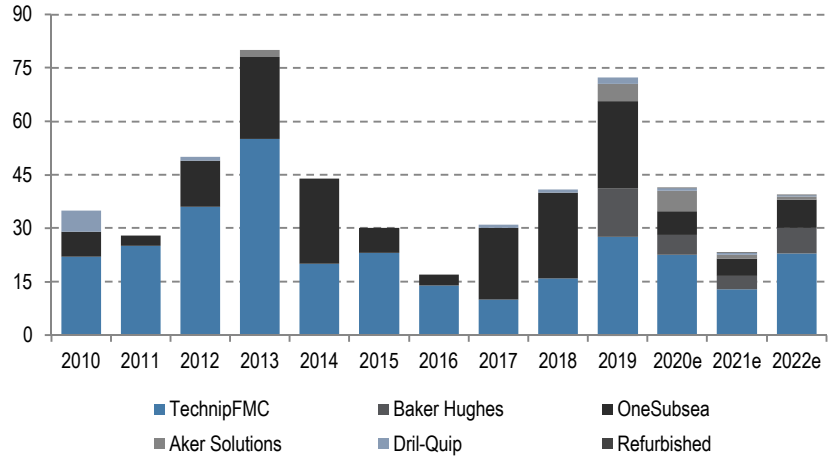
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Projects only delayed once (for now) but brownfield work and M&A to hurt overall subsea activity and pricing

Several trends keeping a lid on subsea spend

One of the mantras of this downturn has been, "not cancelled, just delayed", and across the board that was the case for projects in the U.S. Gulf of Mexico. With spend pushed right, WoodMac expects Subsea capex to bump up in 2021, but then tick lower in 2022/2023. Exploration was cut considerably this year, meaning operators will continue to focus on cheaper, low-risk areas near existing infrastructure, not boding well for subsea OEMs. This trend of remaining laser-focused on costs is obviously nothing new; last year Shell's Power Nap project had a breakeven in the low $30s and BP's Nearly Headless Nick came online just one year after discovery. Although inflation was just starting to return, any hope of pricing power is gone in the near term, with drilling efficiencies and tie-backs also putting a lid on capex. For trees, the GOM was already cooling this time last year in our view and if those important FIDs (as seen above) continue to be pushed right our forecast below will be biased lower. After an M&A pause in 2020, we expect to see increased consolidation in the GOM as the forward curve stabilizes and operators look for fields with both cost synergies and (increasingly in focus) decarbonization potential.

Figure 207: Actual and JPMe OEM Awards in GOM



Source: Company reports, Wood Mackenzie, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

International: Uncertainty Reins…

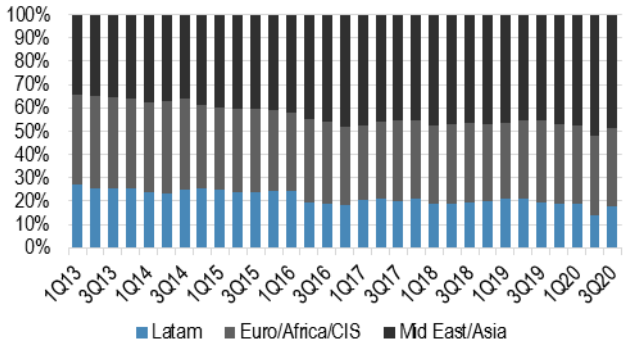
… Putting 2021/2022 Activity Expectations at Risk

Operator belt-tightening and re-allocation of capital are considerable headwinds beyond the pandemic

International spending looking flattish with a downward bias next year

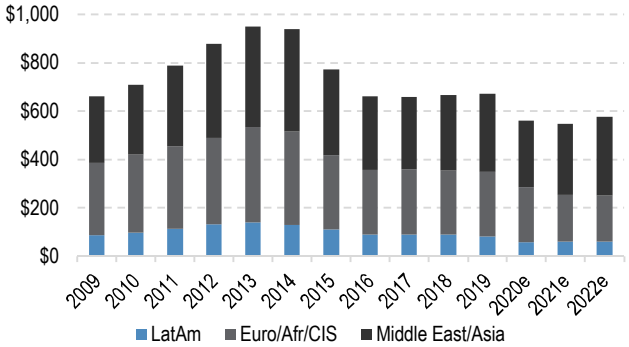
Since our initial Global E&P Capex Survey in April, we have seen 2021 spending outlooks tick lower among IOC/NOC producers as portfolios are high-graded, efficiencies are found and capital flows (or is at least planned for) elsewhere (e.g., balance sheet, shareholders and new energy). As a result, we expect international spending to be slightly down y/y as the "known unknown" of oil demand's recovery from COVID-19 likely lingers in 1H21 despite the positive recent vaccine data points. In 3Q20, aggregate international OFS revenue among the three diversifieds fell -27% y/y on average with the whole down -32% (weighed down by SLB).

Figure 208: OFS International Revenue (% Mix)



Source: Company reports. Note: shows International revenue of SLB, HAL.

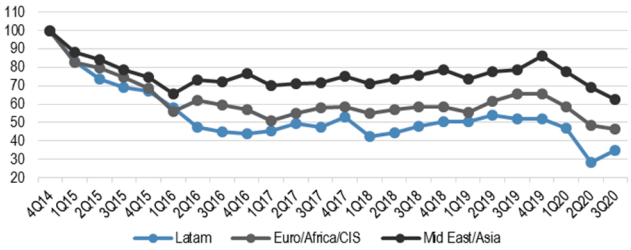
Figure 209: E&P International Capex & Opex ($bn)



Source: Rystad, J.P. Morgan estimates.

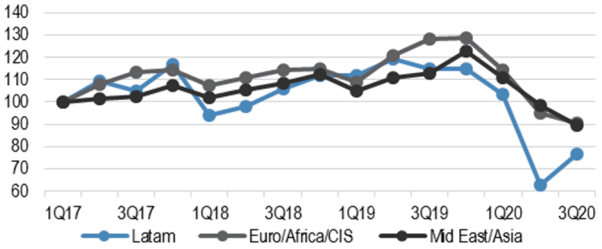
As of 3Q20, LatAm revenues among OFS companies have fallen the hardest (-42% y/y) but after being disproportionately impacted by COVID-19 complications, the region bounced back +11% v. 2Q20 levels. The Middle East and Asia region was (unsurprisingly) relatively shielded this year, down the least at -24% y/y but continues to tick lower (-9% q/q). Europe/Africa/CIS was in the middle of the group, falling -34% y/y with continued weakness in 3Q20 (down -10% q/q). By comparison, OFS revenues from LatAm and Europe/Africa/CIS are now ~64% below 2014's peak and ME/Asia is ~56% lower. The three regions are also 10-20% below the prior trough in 2017 (see below).

Figure 210: OFS International Revenue by Region, Indexed from Peak



Source: Company reports. Note: shows International revenue of SLB, HAL

Figure 211: OFS International Revenue by Region, Indexed from Trough



Source: Company reports. Note: shows International revenue of SLB, HAL, WFT

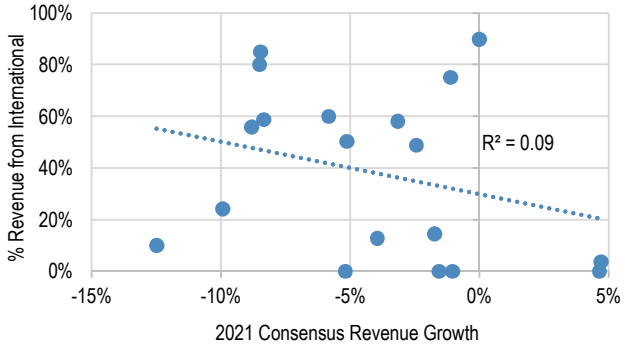
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Limited macro clarity, low starting point keep us cautious on the magnitude of recovery in 2021

Flat 2021 outlook with a weak entry rate still built on hopes of a 2H ramp

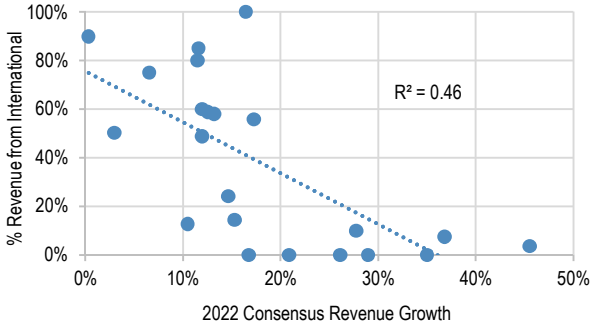
Diversified OFS companies have kept 2021 international expectations tempered in the last few earnings calls. On the 3Q call, **SLB** noted that the next few quarters would be a transition period at the trough of the cycle and given the relative (lack of) strength in 1Q20, y/y growth in 2021 is not realistic. International rig count ticked up +2% off the October bottom, but with current activity still 20% below average rig count in 2020, the road to recovery could be a long one. The scenario of extended sluggishness in activity mirrors how SLB is positioning its portfolio as it has come to appreciate the fundamental differences between this cycle and previous ones. **HAL** cautioned a slow start to international sales in 2021 as 1Q is generally seasonally weaker and the company anticipates more of its work will be weighted to the back half of 2021, importantly impacting the D&E business. **BKR's** commentary was conservative, citing an uplift in 1H21 activity (from low bases) with the back half still facing uncertainty. Given international's 2020 exit rate, the company thinks 2021 activity could be down 5-10% overall. Baker noted that if the curve supports ramping production in 2022, it would still only expect drilling to be focused on the lowest cost basins. We note that since these comments, vaccine deployment has become a reality, clearing up of the initial concern for next year. **Overall, we model international revenue for the diversifieds down ~4% with an uptick of ~6% in 2022.**

Figure 212: Coverage Group Consensus 2021 Revenue Growth v. JPMe International Revenue Mix



Source: Company reports, Bloomberg Finance L.P., J.P. Morgan estimates. Note: Excluding LBRT due to OneStim acquisition.

Figure 213: Coverage Group Consensus 2022 Revenue Growth v. JPMe International Revenue Mix



Source: Company reports, Bloomberg Finance L.P., J.P. Morgan estimates.

2021 consensus seems reasonable with 2022 expected to ramp

Screening consensus revenue as a proxy suggests expectations for MSD declines in 2021 international spending (notably of a sporadic nature). However, isolating those with the highest North American exposure points to a flatter environment, ranging from -5% to +5%. Those with the greatest expected growth next year are idiosyncratic growth/M&A stories (NESR/LBRT), as well as those most levered to NAM completions. In 2022, the Street is clearly baking in lower growth expectations internationally relative to North America (see above), helped by NAM drillers ramping. On the whole, we urge caution given the all-too consistent view that OFS activity inflections seem to always on the two-year horizon. Still, as we look towards 2023, there are more pillars for (modest) optimism on the international cycle.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

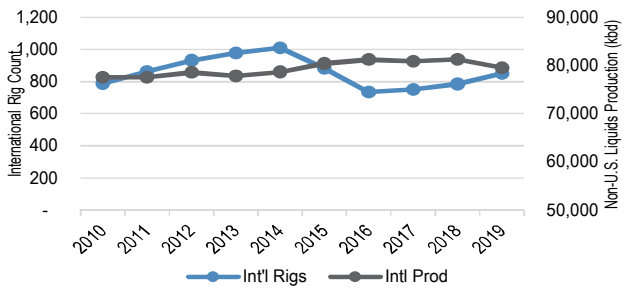
…But the Cycle Could Gain Some Momentum Again in 2023

As oil demand normalizes, we see prospects for upstream capex reengagement

We've been on the bearish side of the global E&P capex cycle debate for more than half a decade now, with only episodic sprinklings of placidity when spending more/less stabilized. While our EU colleagues are fairly full-throated in their endorsement of a coming super-cycle in upstream spend, we're more reticent to embrace that thesis within an investable timeline of say 3-5 years. However, the further the industry separates from the benefit of pre-2014 project sanctions, and the artificial backlog of economically viable projects created by the pandemic normalizes, we think there's room for an acceleration in 2023.

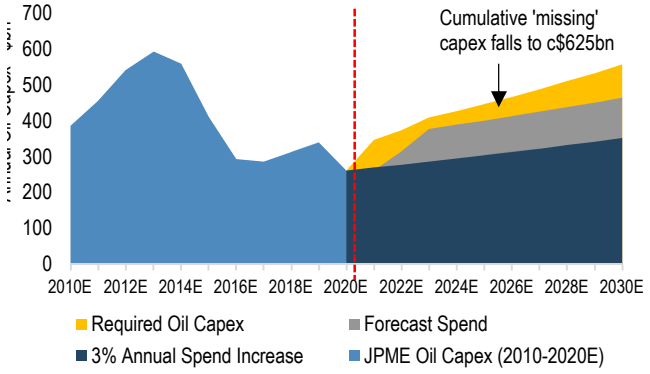
Normalizing the upstream capital cycle into the middle of the decade should be bolstered by 1) higher reinvestment in core Middle Eastern OPEC markets (Saudi, UAE), 2) Guyana/Suriname hitting full stride on development, 3) Continued solid activity in the North Sea, 4) the potential for Brazil to reaccelerate thanks to meaningful projects from Petrobras and Equinor, and 5) large-scale LNG projects (e.g., Mozambique LNG) should require significant gas field development. If oil demand normalizes faster, some of this sanctioned work could be pulled into 2H21 but given the pace at which these operators move, we err towards 2023. **We see a better cycle ahead for 2023-2025 from current activity levels, though not enough to avoid activity and earnings power for most in int'l OFS lower cycle/cycle.**

Figure 214: International Rig Count and Liquids Production (RHS)



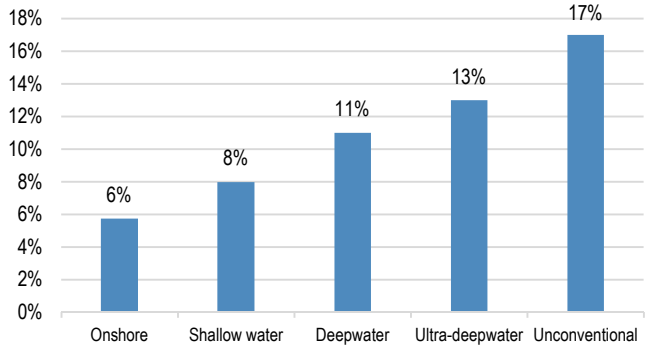
Source: EIA, Baker Hughes.

Figure 215: Potential Oil Capex Catchup Spending



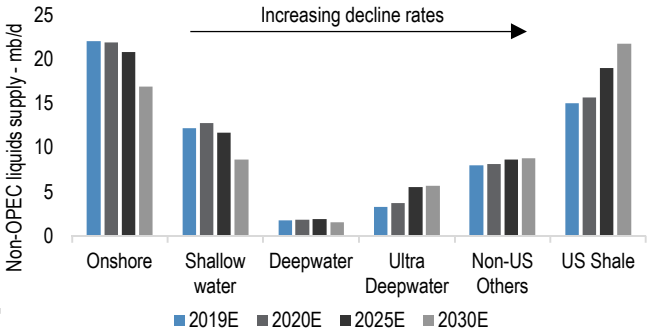
Source: J.P. Morgan Euro Oils Research.

Figure 216: Non-OPEC Decline Rate (%)



Source: J.P. Morgan Euro Oils Research, Wood Mackenzie.

Figure 217: Non-OPEC Decline Rates by Total Liquids Supply



Source: J.P. Morgan Euro Oils Research, Wood Mackenzie.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

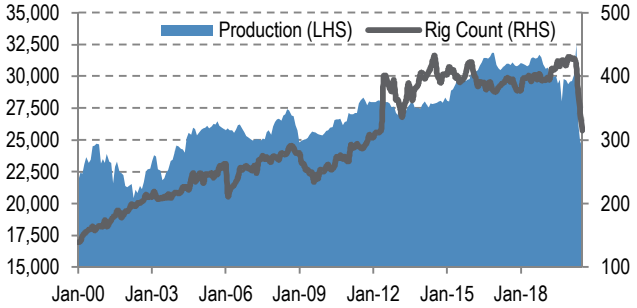
Middle East and Asia: NOC Plans (Mostly) Intact with Gas Projects Providing a Buffer; Asia Hanging in Best

Middle East: not spared in the crash but advantaged going forward

The Middle East rig count suffered from a quick decline in 2020, with the largest drops in Iraq and Qatar YTD, down -65% and -57%, respectively. We expect rig counts to recover in 2021 across the Middle East but still be down -8% on the year, exhibiting less downside compared to other regions. The diversifieds in the region expect a back half-weighted pick-up in activity in 2021 as OPEC+ barrels come back online, easing regional budget constraints.

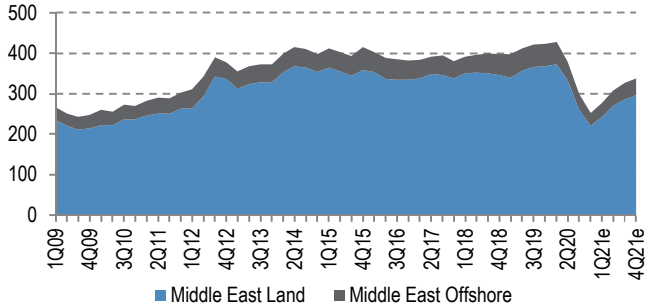
After project sanctioning troughed in the region in 2020, we expect a slight recovery in 2021 as previously delayed projects reach FID. Rystad estimates the Middle East will produce $79bn in project commitments from 2021-2025, with ~half of spend being contributed by the Zuluf Expansion, QatarGas LNG T8-T11 and the Hail & Ghasa ultra-sour projects (FID delayed at least a year). No major new projects started up in the region this year, but an onshore brownfield project in Iraq is expected to begin drilling in 2021. Qatar's North Field Expansion (32mtpa) recently produced a ~$1bn award for BKR, and we expect FTI to win scope of a similar size in 1Q21. Clad pipe requirements for NFE are also expected to be awarded around the same time frame. The North Field South FID is expected in 2022 (16mtpa). The Middle East's OCTG market has experienced headwinds, with Saudi Aramco delaying the development of the offshore Marjan field up to 24 months with several other projects set to follow also likely facing delays. We get more optimistic into the 2023-2025 time frame as the region reverts to the mean on long-term capacity targets.

Figure 218: Middle East Production (000's bbl/day) and Rig Count



Source: EIA, Baker Hughes. Note Data through October 2020. Liquids only.

Figure 219: Middle East Rig Count Forecast



Source: Baker Hughes, J.P. Morgan estimates.

OPEC+ production increases and spending plans not necessarily correlated

We often field inbound investor questions during changes in OPEC+ production changes with respect to the near-term impact to upstream activity. However, the two typically have little or even no correlation, with 2020 an exception to this rule due to the impacts of the pandemic on activity. While OPEC+ is cautiously adding production in January, we do not expect it to tie to an increase in spending immediately. A divide between Saudi Arabia and the U.A.E. is a potential concern, with the former focused on keeping the cuts in place and the latter on improving compliance from overproducing countries. We also expect that a Biden administration in the U.S. will likely result in a boost to Iranian production in the back half of 2021 as it is presumed the administration will make de-escalating tensions with Iran a priority.

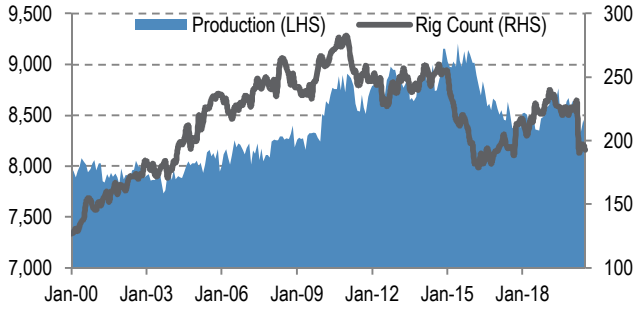
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Asia Pacific: Quicker recovery expected, with LNG the longer-term attraction

The region provided the strongest growth of all in 2019 and is experiencing a recovery in regional oil demand ahead of global levels, driven by China. As a result, we think production could remain relatively flat or slightly recover in 2021. The region has still experienced numerous project delays as companies focus on conserving capital over growth, resulting in Australian LNG projects taking the largest hit. FIDs for Barossa, Scarborough, and Browse now delayed, making 2022 a key investment year if operator confidence improves. After the region's exploration spend declined 20% this year, Rystad expects it to be on an upwards trajectory through 2025 (~60% growth v. 2020). Most of the growth stems from conventional offshore ($48bn) with offshore shelf seeing $12bn in investments, and China dominating the mix.

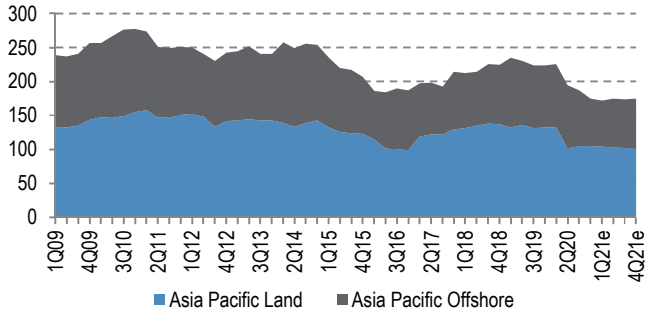
The Julimar-Brunello Phase 2 project was sanctioned by Woodside last year and drilling was completed in October with subsea installations expected in 1H21. The company also completed drilling for the Pyxis Hub this year. FID for the Scarborough and Pluto Train 3 projects is now targeted for 2H21. Meanwhile, changes in politics in Papua New Guinea has resulted in TOT's Papua LNG project likely advancing in front of XOM's P'nyang gas field development. Papua New Guinea has pushed for a bigger stake in XOM's development of the field, resulting in a stalling of the project. We expect LNG expansion to continue in the country as the partners work to meet future demand increases as in the future as APAC countries switch from coal. In 2021, Baker Hughes sees relatively flat OFS activity in Southeast Asia, prompted by more stability in China.

Figure 220: Asia Pacific Production (000's bbl/day) and Rig Count



Source: EIA, Baker Hughes. Note Data through October 2019. Liquids only.

Figure 221: Asia Pacific Rig Count Forecast



Source: Baker Hughes, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Latin America: Activity Ramp Put on Ice for Now; Offshore Outlook Advantaged, Onshore Bounce in the Works

Hit hard by COVID-19, operations were halted; offshore outlook better than onshore; medium-term could be more encouraging

Congress action likely in Brazil as recent auctions disappoint

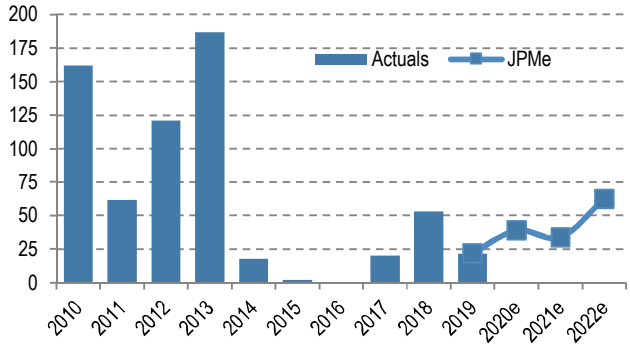
Brazil's National Petroleum Agency only sold one offshore block at its 2nd acreage auction this year (RSD purchased the C-M-757 block in Campos Basin). With no interest in the other 34 offshore blocks, Congress is expected to look at further changes to its production sharing guidelines with implementations next year. One can blame the macro here, but after disappointing showings last year, it is becoming increasingly clear Brazil needs to cut some slack for operators in order to incentivize incremental investment. After being put on hold this year, the 17th bid round and second ToR sale are anticipated to resume in 2H21.

Investment flowing to the lowest cost offshore basins

The upstream has been laser-focused on high-grading portfolios and only allocating spend to the top tier projects, which for offshore, tend to be offshore South America. Just as Petrobras was making solid progress on executing its considerable growth plans, the pandemic has forced it to take table some near-term steps (but it still plans to bring on thirteen production units from 2021-2025). The NOC recently released a revised plan calling for $55bn in investments over the next five years which is ~$21bn less than previously planned in the 2020-2024 span. Approximately 70% will be geared towards pre-salt (with a focus on Buzios) and 22% will be allocated to post-salt fields (e.g. Marlim and Roncador).

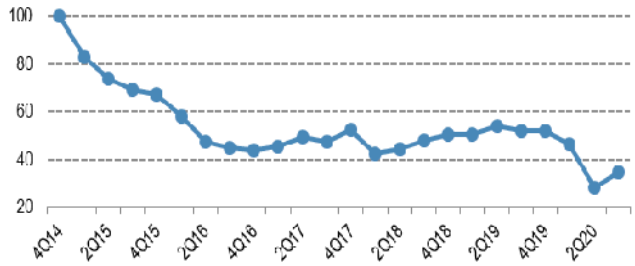
Rystad projects PBR to represent ~40% of the total SURF installations in the Americas (v. 73% from '16-'20). Petrobras awarded OII a one-year BOP tethering services contract, and we expect the company to continue focusing on expanding its presence in Brazil. Equinor has made a sizable splash with its Bacalhau project, resulting in contracts for SLB, BKR, and HAL totaling ~$455mm; FID is expected in 2021 with production planned to start in 2024. In 2020, two deepwater projects came under development in Brazil (Petrobras' Mero-4 and Itapu) and one in Guyana (XOM's Liza). XOM continues to prioritize its prolific Stabroek block off Guyana, with Payara now sanctioned (FTI supplying the trees). Brazil, Guyana and Suriname will continue as bright spots but we remain on the lookout as it can be tempting for OFS to chase volume over value in order to get a foot in the door.

Figure 222: Historical and Projected LatAm Subsea Tree Awards



Source: Wood Mackenzie and J.P. Morgan estimates.

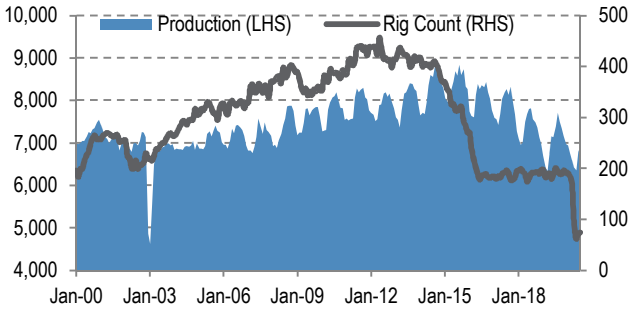
Figure 223: Historical Diversifieds LatAm Revenue (as % of 4Q14 exit)



Source: Company reports, J.P. Morgan estimates. Note: Large Caps consist of HAL and SLB

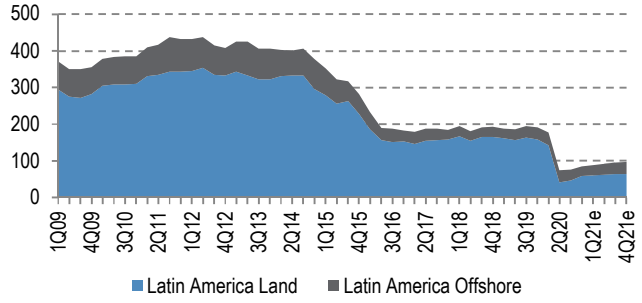
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 224: LatAm Production (000's bbl/day) and Rig Count



Source: EIA, Baker Hughes. Note Data through October 2019. Liquids only.

Figure 225: JPM Latin America Rig Count Forecast



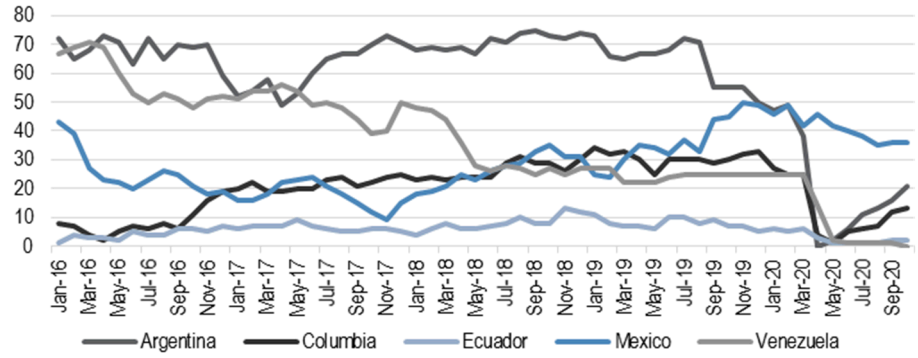
Source: Baker Hughes, J.P. Morgan estimates.

Argentina looking to incentivize natural gas production recovery

Onshore bouncing back hard from the lowest of lows

Under its new government, Argentina is expected to award contracts for its natural gas tenders soon. The country is aiming to reverse falling natural gas production, and expects the plan to result in producers investing over ~$6bn during the next four years. Colombia has seen an increase in conventional activity, however unconventional remain depressed; following CVX's sale late last year, OXY followed suit and sold its onshore Colombian assets. Within our coverage, the primary service providers in the region are the diversifieds, H&P and Tenaris. Halliburton has exposure to Vaca Muerta (and HP has aspirations to add back some rigs in 2021). After selling Bandurria Sur in January, Schlumberger's APS projects in the region are now limited to Ecuador and Colombia (along with discrete service contracts).

Figure 226: Total Rig Count in Key Latin American Countries



Source: Baker Hughes.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

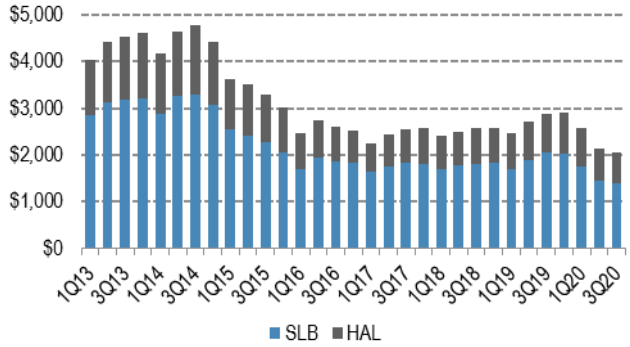
Europe, Africa and Russia: Norway Looking World-Class; African Development Dwindles; Arctic Gas Intact

Russia constrained by production cuts, LNG investment continues to progress

Russia remains competitive on the LNG front, however a lack of technologies (due to sanctions) and an uncertain future for Europe as its main gas consumer are risks. On the project front, Yamal LNG is on track, now past peak revenue recognition for FTI, and its second mega project Artic LNG-2 is expected to begin production in 1Q21. FTI was also contracted to design a ~$10bn plant for another project in Yakutia, with hopes to reach completion in 2025. While development overall is still progressing, Novatek's Obskiy LNG project which was initially expected to FID in 2020 has been postponed until 2024.

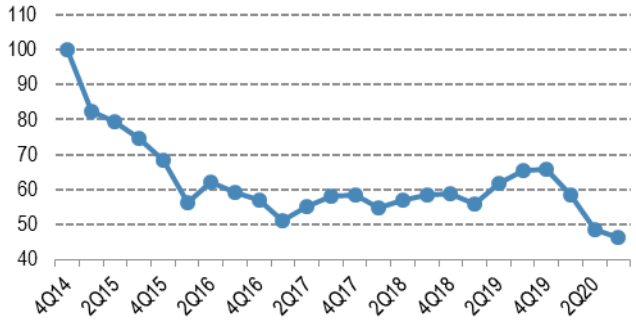
The Russian government also introduced an initiative to support large domestic independent and integrated OFS companies in May, given the restrained production from COVID-19 and OPEC+ compliance. The Russian Energy Ministry worked with banks, operators and OFS companies to set up special purpose vehicles to provide funding in the downturn. On the drilling front, Shell and Gazprom Neft are set to seal a JV deal by the end of the year which will allow them to start drilling exploration wells offshore the Gydan Peninsula next year. In other Eastern European updates, Uzbekneftegaz (UNG), Uzbekistan's NOC, has been stripped of supervision functions as the country continues to restructure it into an E&P company; since January, Epsilon Development has announced nine oil discoveries in the country. In Azerbaijan, XOM followed CVX by confirming its intent to exit.

Figure 227: Diversifieds Europe/Africa/CIS Revenue ($mm)



Source: Company reports.

Figure 228: Diversifieds Europe/Africa/CIS Revenue, Indexed to 4Q14



Source: Company reports. Note: shows revenue of SLB and HAL.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Fiscally supported Norway market to continue to outpace the U.K.

With a combo of COVID-19, operator discipline and private equity reshuffling, many programs in the U.K. have been (and will continue to be) pushed to the right; total North West Europe rig count has retreated back to previous cycle lows. We expect both the jackup and floater markets in Norway to be considerably tighter than in the U.K., given better rationalized supply and nearly opposite demand pictures. With that relative strength comes the risk of new entrants (which has been the case recently), helping to limit dayrate acceleration in the coming years. For example, Transocean is trying to get a piece of the action by marketing the *Barents* for a few opportunities.

Norway's stimulus has created a relative bright spot in OFS

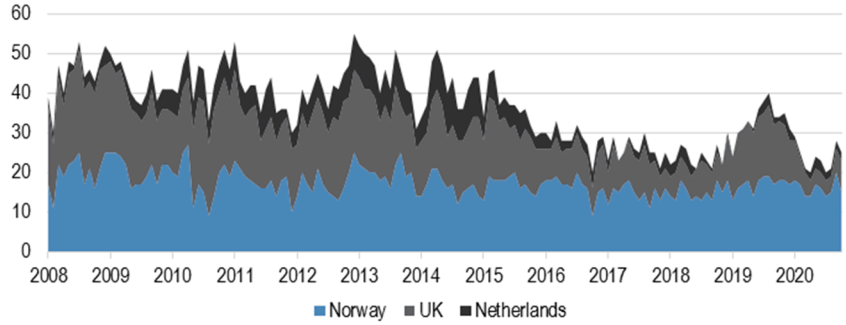
In the middle of the downturn Norway granted tax incentives for projects approved through the end of 2022, incentivizing investment in its vital energy industry. The impact can be seen in the table below; even after several programs reached FID in 2020, the amount of Norway capex on the table in the next few years triples that of the U.K. market. In Norway, while Equinor accelerated projects, it has also delayed others, including the Johan Castberg Field (now expected on stream in 4Q23), Martin Linge (2021), and the Njord field (2021). COP's Eldfisk subsea tieback has experienced delays from severe weather and worker strikes (a trend in the region that seems to have been resolved). Norway's Breidablikk field is progressing: FTI signed a contract for pipe-laying and subsea installation, WG was awarded an EPCI contract, and AKER received scope as well. Odfjell Drilling was awarded a 15-well contract for the project as well. Baker Hughes expects its North Sea revenues to be flattish in 2021, citing the fiscal support.

Table 19: North Sea Pre-FIDs to Watch

Project	Country	Type	Operator	Expected FID	Expected Startup	Capex ($mm)	Reserves (mmboe)
Jackdaw	**U.K.**	Greenfield, Platform	Shell	Jan-22	Oct-25	$850	79
Glendronach	**U.K.**	Greenfield, Subsea	Total	Mar-22	Nov-23	$1,120	100
Rosebank	**U.K.**	Greenfield, FPSO	Equinor	May-23	Jun-28	$4,700	320
Clair South	**U.K.**	Brownfield, Platform	BP	Jul-24	Jun-28	$4,800	283
Tommeliten Alpha	**Norway**	Greenfield, Subsea	ConocoPhillips	Mar-21	Nov-23	$760	125
Lavrans	**Norway**	Greenfield, Subsea	Equinor	Feb-22	Sep-24	$740	83
Haltenbanken East	**Norway**	Greenfield, Subsea	Equinor	Jul-22	Jul-25	$1,200	85
Ormen Lange	**Norway**	Brownfield, Subsea	Shell	Jul-22	Jun-25	$1,270	243
Asterix	**Norway**	Greenfield, Subsea	Equinor	Sep-22	Sep-24	$990	106
NOAKA	**Norway**	Greenfield, Platform	Aker BP	Oct-22	Jan-27	$6,800	509
Garantiana	**Norway**	Greenfield, Subsea	Equinor	Nov-22	Jun-25	$1,350	80
King Lear Area	**Norway**	Greenfield, Platform	Aker BP	Nov-20	Jun-25	$1,600	128
Wisting	**Norway**	Greenfield, FPSO	Equinor	Dec-22	Jul-27	$6,700	455

Source: Wood Mackenzie, J.P. Morgan estimates.

Figure 229: NW Europe Rig Count



Source: Baker Hughes.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

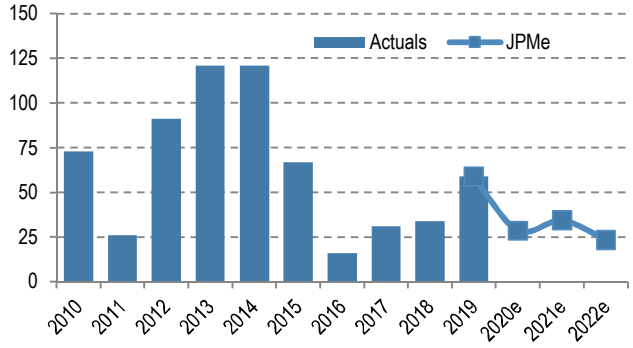
Operators divert spend elsewhere; region remains in need of political support to capitalize on long-cycle offshore projects

Africa sanctioning delays likely limit activity increase in the near-term

We expect Africa's total rig count to decline by ~35% in 2020, with land bouncing back in 2021 (still slightly down for the year) and offshore continuing to move lower with limited work scope as rigs roll off. Activity seems to be at a turning point as FID's have declined due to both COVID-19 and the shifting focus of IOCs to cleaner energy. Per IHS, three projects make up ~50% of potential FIDs in 2021: Block 32 and Agogo (both Angola) as well as Etinde in Cameroon. The FID for Block 32 has been potentially pushed to 2022 from 2020. Agogo is operated by ENI and a 2021 FID (Phase 2) seems likely per company commentary. The FID for Etinde was deferred from 2020 to 2021 due to COVID-19 and other factors. As of now, six projects have been delayed from 2021 to 2022. Rystad expects next year to mark the low point, with estimated commitments of $4bn to date (v. ~$14bn in 2020). In the trough of the downturn, we expect operators to focus on brownfield spend. Rystad estimates Africa's SURF market could total ~$14bn through 2025 with about half allocated to subsea tiebacks. The majority of projects will stem from Angola (followed by Nigeria and Egypt).

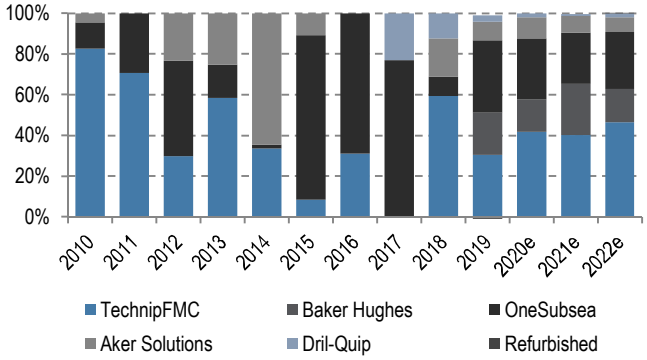
Despite the downturn, Somalia launched its first offshore licensing round in August and is accepting bids on seven blocks until the end of 1Q21. The round came after a new petroleum law was put in place in early 2020 to pique the interest of upstream players, establishing a framework for both onshore and offshore activity. As a result, an agreement was reached with a RDS-XOM JV in the same month for the exploration of historic offshore O&G blocks in the future.

Figure 230: Actual and JPMe Africa Subsea Tree Awards



Source: Company reports, Wood Mackenzie, J.P. Morgan estimates.

Figure 231: Actual and JPMe Africa OEM Market Share



Source: Company reports, Wood Mackenzie, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Midstream: Downturn Drives ~30% Reduction to Spending y/y

With Midstream Capex Lagging Upstream Activity, we see Scope for a Sizable y/y Decline

Average 2021 capex is down -31% y/y across JPM's coverage group

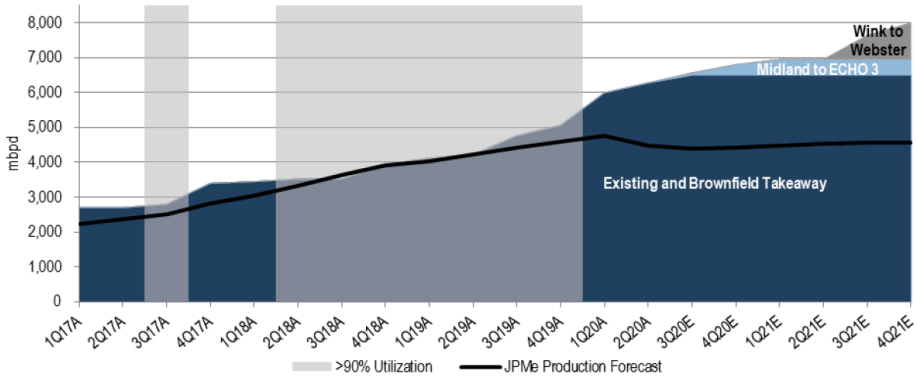
Looking across the 35 midstream companies under JPM coverage, we see an average y/y capex decline of ~30% in 2021, similar to the -31% decrease expected in 2020. This view shapes our outlook for a shrinking opportunity set for midstream OFS sales next year, though we acknowledge the difficulties in aligning OFS midstream exposures to overall pipeline infrastructure budgets. With existing pipeline capacity expected to outstrip demand throughout next year and investor calls for capital discipline, midstream providers are pulling back on expansion investments. Over time midstream capex should follow production, and given our flattish production outlook into 2022, this sets up a limited growth landscape in the near-to-medium term. MRC confirmed such a view with commentary that it expects to see pressure y/y in midstream because the projects that began in 2019 and 1Q20 will begin to taper off, with few replacements on tap. Additionally, line pipe pricing remains under pressure, contributing to the lower overall spend needed from midstream providers.

Figure 232: Permian NGL Greenfield and Brownfield Capacity Additions

Company	Pipeline	Destination	Gross Capacity (mbbls/d)	Net Permian (mbbls/d)	In-service	Shippers	FID
In-Service							
ET	Lone Star NGL Express	Mont Belvieu	507	375	Y	Multiple producers, ET plants	N/A
ET	Lone Star West Texas Gateway	Mont Belvieu	240	150*	Y	Multiple producers, ET plants, EagleClaw	N/A
DCP	Sand Hills	Mont Belvieu	500	390	Y	APC,WES/TRGP plants, other E&Ps	N/A
OKE	West Texas LPG	Mont Belvieu	285	175*	Y	Multiple producers, TRGP plants	N/A
EPD	Seminole/Chaparral/Rio Grande	Mont Belvieu/Other	320	25*	Y	EPD plants, third parties	N/A
CP Chem (PSX)	Line EZ	Sweeny	100	80*	Y	PSX, CVX	N/A
OKE	West Texas LPG	Mont Belvieu	40	40	Y	Multiple producers, TRGP plants	N/A
EPD	Shin Oak (Full ramp)	Mont Belvieu	550	550	Y	APA, EPD legacy, Orla I-III & Mentone plants	N/A
TRGP	Grand Prix (Mainline)	Mont Belvieu	250	250	Y	TRGP/EagleClaw plants, third parties	N/A
OKE	West Texas LPG	Mont Belvieu	80	80	Y	Multiple producers	N/A
Ares Mgmt	EPIC Y-Grade	Corpus Christi	440	200*	Y	BP, NBL, WPX, Ramsey/Black River/Brazos etc.	N/A
ET	Lone Star NGL Express	Mont Belvieu	400	400	Y	Multiple producers, ET plants	N/A
FID/Development							
TRGP	Grand Prix (Phase I)	Mont Belvieu	100	100	TBD	TRGP/EagleClaw plants, third parties	Y
Ares Mgmt	EPIC Y-Grade Exp.	Corpus Christi	600	480*	TBD	BP, NBL, WPX, Ramsey/Black River/Brazos etc.	N
Deferred/ Cancelled							
MPLX/White Water/Others	BANGL	Texas City	-	-	TBD	MPLX plants	N

Source: J.P. Morgan Energy Infrastructure & MLP Equity Research

Figure 233: Permian Pipeline Capacity v. Demand



Source: J.P. Morgan Energy Infrastructure & MLP Equity Research, company reports.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

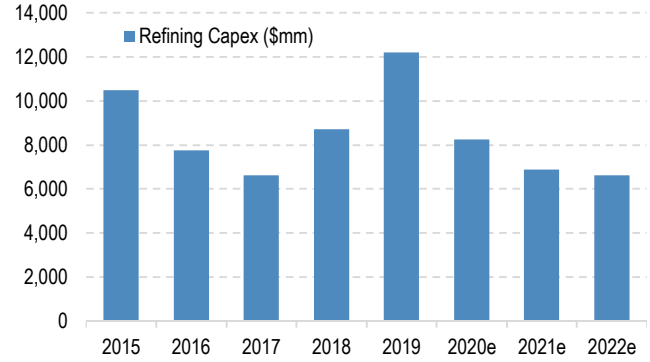
Downstream: Tracking Mid-Teens y/y Spending Decrease

Maintenance Spending to Define Most Refining Capex in 2021; Delayed Turnarounds Offer Some Upside

Refinery utilization should trend directionally higher in 2021, but y/y capex is set to move lower

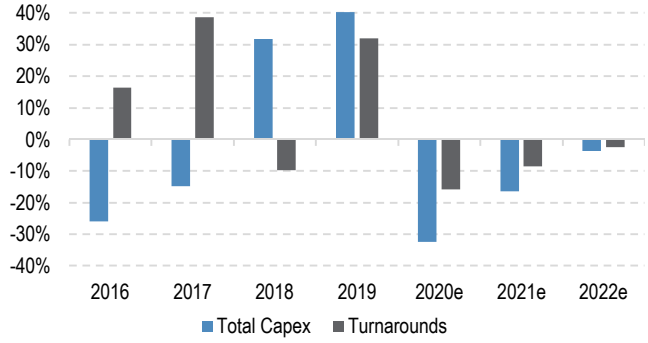
We are anticipating downstream capex to fall mid-teens y/y in 2021 based on spending assumptions for JPM's refiners coverage as a proxy, outpacing our preliminary estimate for a -MSD y/y decline for upstream spending from U.S. E&Ps. Though refinery utilization levels are set to continue to increase off of their COVID-driven troughs next year (see thoughts from our Refining colleagues here), commentary from our PVF distributors suggests that capex will be primarily targeted at maintenance levels, setting up the weaker spend next year. That said, we acknowledge the difficulties in discerning the addressable wallet for OFS from overall refining budgets (allowing for a wider margin for error). A bright spot for the distributors may be turnaround spending (and Tenaris), much of which was pushed off in 2020 due to the downturn, but may be unable to be delayed further in 2021.

Figure 234: U.S. Refining Capex ($mm)



Source: J.P. Morgan U.S. Integrateds & Refining Equity Research
Note: Group includes DK, HFC, MPC, PBF, PSX, VLO

Figure 235: U.S. Refining Capex and Turnaround Spend, Growth y/y



Source: J.P. Morgan U.S. Integrateds & Refining Equity Research
Note: Group includes DK, HFC, MPC, PBF, PSX, VLO

Downstream capex may fall y/y, but represents source of stability for select OFS

MRC guided its Downstream sales to fall HSD q/q in 4Q20, setting up a lower run-rate into 2021. The downstream PVF leader sees a relatively good spring turnaround season ahead due to many larger-scale projects being pushed from 2020 into 2021. Otherwise, maintenance spending is expected to form the majority of refiner capex. While we think this translates to a -10% y/y volume decline for MRC's Downstream segment, we see less volatility among these volumes than in other segments. DNOW is open about its interest in pursuing bolt-on acquisitions, and has indicated that downstream might be a likely target for M&A due to the diversifying potential for its sales mix. The challenging demand environment could help the bid-ask spread narrow for some deals in 2021. In addition, our outlook for downstream EPCI and compression equipment remains relatively good, evidenced by FTI's current backlog of ~$7bn in downstream, refining, and petrochemical projects (including ~$2bn of ANOPC inbound in 4Q).

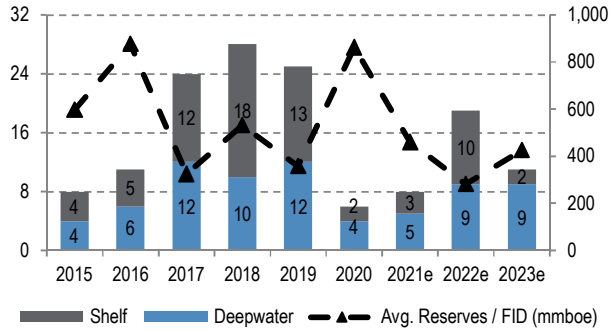
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Offshore Reset Lower But Not For Longer

Offshore Drilling Remains Disadvantaged While Subsea Takes a Pause Before Heading Higher

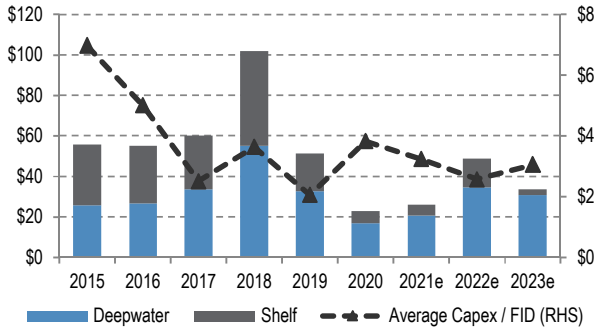
The downturn pushed out many offshore projects and concerns on the macro, while investor scrutiny and energy transition pressures heighten the risk of fringe projects being pushed further. We think overall subsea spending can return faster than last cycle, which languished after the halcyon days of 2012 through 2014. We expect operator focus to remain on further optimizing footprints with brownfield sanctions and a growing proportion of tiebacks while notable greenfield FIDs look limited in 2021. Trees can retrace to the ~300 level in 2023 in our view while we expect SURF to grow at a ~8% CAGR through 2025. Contracting in 2021 for offshore drilling is pointing to y/y declines across rig types with outsized risks of tendering delays in our view, hopefully prompting supply rationalization as demand potentially undershoots.

Figure 236: Number of FIDs (LHS) v. Average Reserves (RHS)



Source: Wood Mackenzie, J.P. Morgan estimates. Note: Assumes $50 Brent breakeven.

Figure 237: Total FID Capex ($bn) v. Average Capex ($bn)

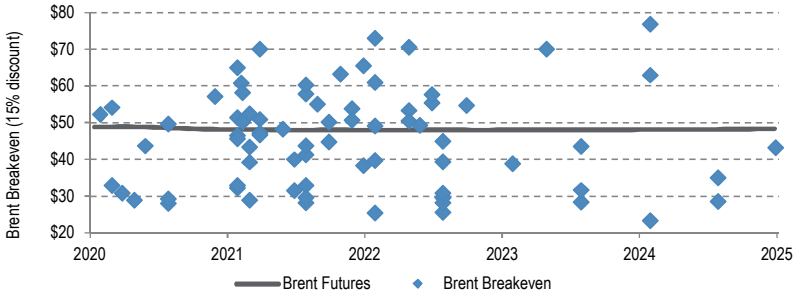


Source: Wood Mackenzie, J.P. Morgan estimates. Note: Assumes $50 Brent breakeven.

Sanctioning in need of macro clarity and a more supportive futures curve

Higher average capex per FID of ~$4bn in 2020 helps buffer spend in the coming years (on a relative basis) as only six projects came through the pipeline in 2020. Deepwater made up a greater share of the mix bolstered by XOM's Payara development in Guyana and PBR's Mero 3 and Itapu. Programs off Norway and Senegal (EQNR's Breidablikk and Woodside's Sangomar, respectively) provided a much needed shot in the arm to orders as well. At $50 Brent (which currently sits just above the futures curve), sanctioning in 2021 could look similarly depressed to this year (see below). The futures curve does not support higher cost (on average) and longer cycle offshore barrels as operators are faced with other, more pressing calls on capital. That said, our long-term gravitational center for Brent remains $60.

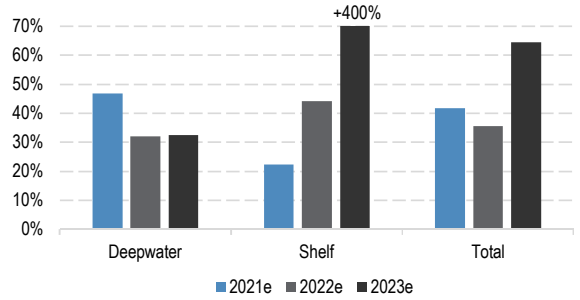
Figure 238: Brent Futures v. Offshore Pre-FID Breakeven and Expected Sanction Date



Source: Wood Mackenzie, J.P. Morgan estimates, Bloomberg Finance L.P.

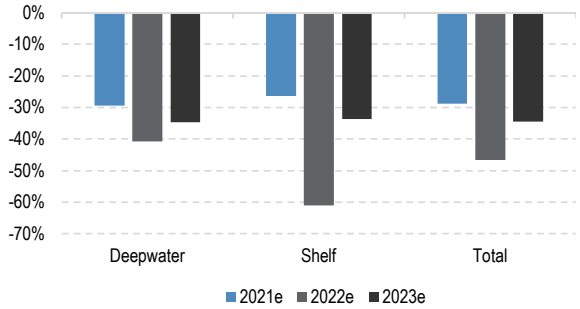
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 239: FID Capex Sensitivity for $60 Brent v. $50 Brent



Source: Wood Mackenzie, J.P. Morgan estimates.

Figure 240: FID Capex Sensitivity for $40 Brent v. $50 Brent



Source: Wood Mackenzie, J.P. Morgan estimates.

Brownfield projects continue to chip away at offshore cost curve

In a more bullish scenario for Brent (~$60/bbl), sanctioning could increase ~40% from 2021-2023 with slightly less risk to the downside for a ~$40/bbl environment, the latter seeming more likely. For projects through 2025 that have breakevens below the $50/bbl mark, our capex estimates currently total ~$180bn v. ~$190bn this time last year. After >$20bn of sanctioning in 2020, the queue continues to be (somewhat) replenished from incremental opportunities and cost curve improvements. We note the year-over-year change in the shape of the cost curve below, now with ~$100bn in economic projects under $40/bbl compared to ~$75bn prior. The sizable capex around the $30 bucket can mostly be attributed to Buzios. Brownfield projects will continue to be prioritized with outsized opportunities at the low end of the cost curve.

Figure 241: Offshore pre-FID Cost Curve Through 2025 as of 3Q19

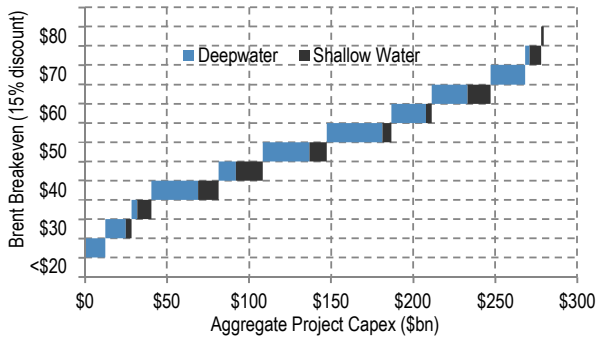


Figure 242: Offshore pre-FID Cost Curve Through 2025 as of 3Q20

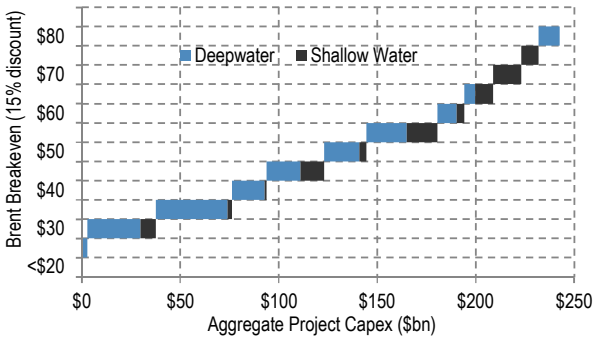
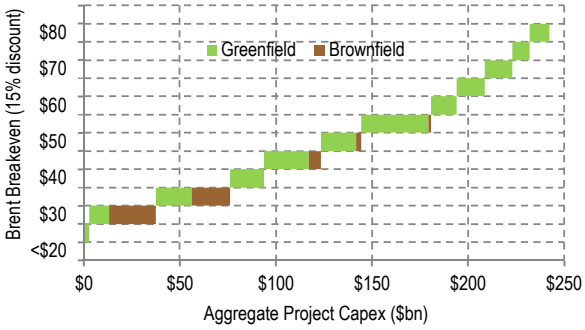


Figure 243: Offshore Pre-FID Cost Curve by Play Though 2025 as of 3Q19

Figure 244: Offshore Pre-FID Cost Curve by Play Through 2025 as of 3Q20



Source for all figures: Wood Mackenzie, J.P. Morgan estimates.

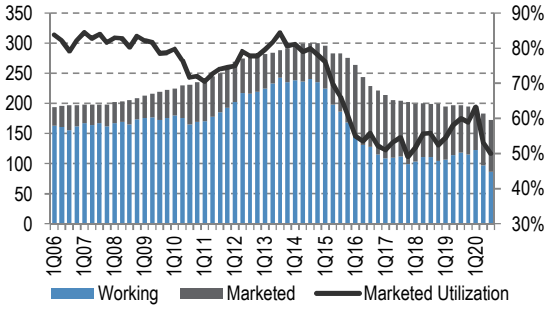
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Offshore drillers need to retire more rigs post-restructuring to bolster dayrates next cycle

Without further supply rationalization, multi-party prisoner's dilemma remains

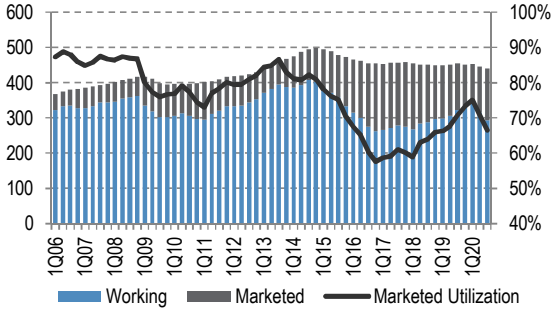
We have been pleasantly surprised by the pace of offshore rig attrition in 2020: six drillships in service since 2010-2012 were scrapped (a few would have been cost prohibitive to reactivate), eighteen semis were retired (20-30 years old) and sixteen jackups exited the global fleet (mostly +30 years old). While the drillship attrition seems relatively low, it's a function of how many drillships have already been stacked for +2 years (or most of last cycle), making them effectively retired at this point. In the coming quarters as rigs roll off contract into a fairly bleak market (see below), we expect contractors to continue to scrap or at least cold-stack rigs to balance the market and foster a reasonable bidding environment in the next cycle. Even with several drillers in restructuring, the market is still struggling with multi-party prisoner's dilemma, taking drillship dayrates near breakeven levels once again to maintain utilization. An important lever is potential driller matchmaking as the companies emerge with rationalized fleets (hopefully), but for an industry that has struggled to adapt to the new normal, this scenario is not in our model at the moment.

Figure 245: Historical Floater Utilization



Source: IHS-Petrodata.

Figure 246: Historical Jackup Utilization

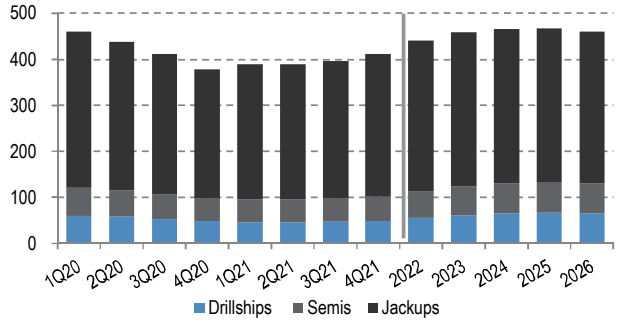


Source: IHS-Petrodata.

Demand pushed out two years (at least) yet again

Floater demand experienced a 14% drop in 2020, and with 2021 mostly in the books, we expect a decline of -9% next year (see below). The open tenders in the table below offer up solid term, but several are likely to continue to be pushed in our view, (with more rebid requests to boot). Clearly operators still have leverage: Diamond's *Ocean Courage* was awarded scope with PBR into 2023 at only $185k/day. Another of PBR's floater tenders recently had bids ranging from $160k/day to $330k/day, but the scope has yet to be awarded as the NOC mulls over rig specs. The jackup market is more exposed to brownfield, P&A and intervention work, shielding it in a downturn. After jackups fell only 3% in 2020, we expect a -6% decline in 2021.

Figure 247: JPMe Offshore Drilling Rig Count Forecast



Source: IHS-Petrodata, J.P. Morgan estimates.

Figure 248: Key Floater Tenders

Operator	Rig Type	Country	Start Date	Duration Range	
Petrobras	Drillship	Brazil	Aug-21	1,095	2,190
Total	Drillship	Mozambique	Oct-21	900	1,630
ONGC	Drillship	India	Apr-21	730	
ExxonMobil	Drillship	Angola	May-22	730	1,450
Mellitah	Semi	Libya	Jun-22	690	1,035
Tullow Oil	Drillship	Ghana	Apr-21	540	540
Santos	Semi	Australia	May-22	500	
Petrobras	Drillship	Brazil	Apr-21	365	
Medco	Semi	Indonesia	Jul-21	365	
Total	Drillship	Nigeria	Dec-21	365	720
Equinor	Drillship	Brazil	Jan-22	365	
ExxonMobil	Drillship	Nigeria	Nov-22	365	1,825

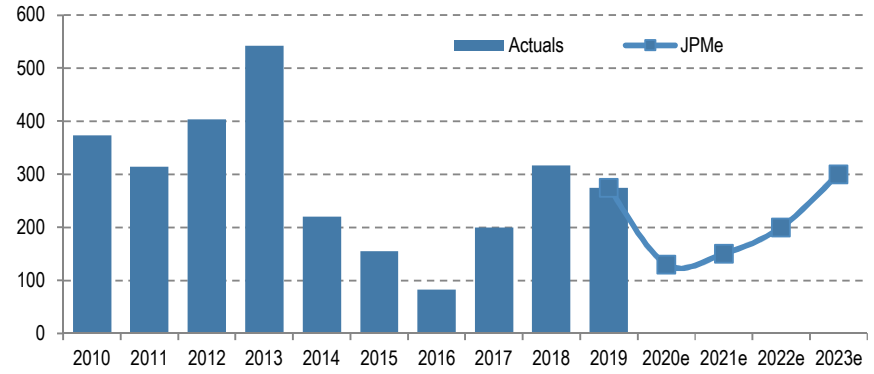
Source: IHS-Petrodata.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Subsea Outlook: Tree and SURF Spend to Return Faster Than Last Cycle, with Normalized Levels Intact

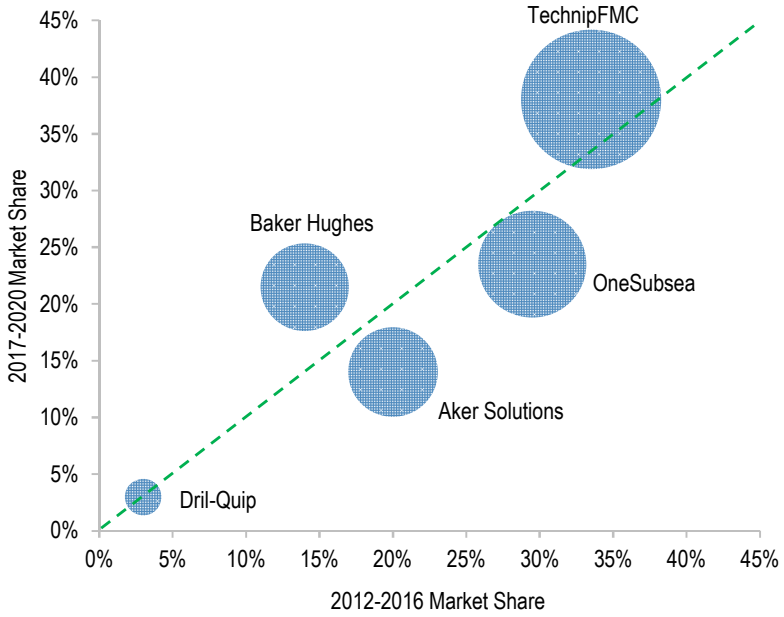
While the most prolific projects were able to make it through the project queue this year, many were pushed and now on track to be sanctioned in 2022 and 2023, potentially allowing for a quicker recovery in subsea spending compared to last cycle. After ~130 subsea trees were awarded in this tumultuous year, we expect orders to progress slightly higher in 2021 and 2022, retracing to the ~300 mark by 2023. Since 2017 both BKR and FTI have picked up share (see below) at the expense of OneSubsea and Aker Solutions (with its focus on Norway and Africa). The economics of the best deepwater projects can still work in this environment and the subsea industry will primarily ride on the back of the dominant players: Petrobras, Equinor and Woodside in their respective regions. Importantly, the swing operators (e.g. XOM, CVX, RDS, BP, TOT) are key to the pace of recovery as portfolios are reviewed with intense capital scrutiny and energy transition headwinds in mind.

Figure 249: JPMe Subsea Tree Award Forecasts, 2010-2023e



Source: Wood Mackenzie, J.P. Morgan estimates.

Figure 250: Subsea Tree Market Share: 2012-2016 (x-axis) v. 2017-2020 (y-axis)



Source: Wood Mackenzie, Rystad, J.P. Morgan estimates. Note: Bubble size reflects total trees awarded from 2012-2020.

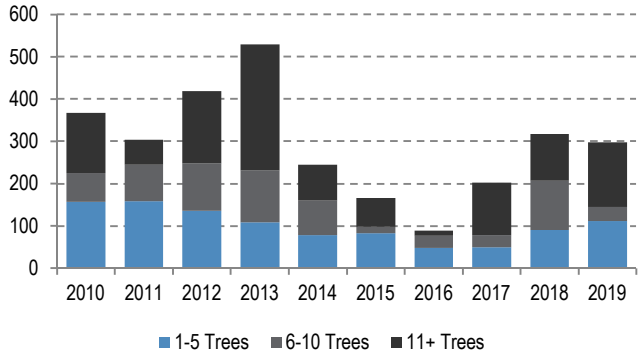
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Path to recovery not evenly distributed by region; brownfield optimization continues to gain momentum, but we still see 200-225 tree awards as "normalized, comparable to the prior cycle"

Back to 300 trees in 2023, driven by LatAm and Norway

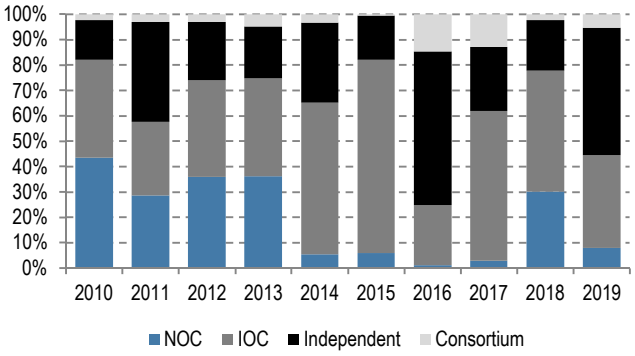
With ~130 subsea trees ordered this year, 2020 was able to surpass the dismal level of ~90 in 2016. The root cause of that achievement was Sangomar, Breidablikk and Payara, accounting for >60% of orders. The market looks to remain touch and go next year but we model 150 trees, which seems to be in-line with the thinking of management teams. We continue to view ~300 trees as a sustainable annual order level in healthy times, which we forecast to be reclaimed in 2023. Rystad projects just ~1,040 trees from 2021 through 2024 (an annual average of ~260), a bit optimistic in our view. With destocking mostly out of the way in LatAm, the region has made a grand reentrance in the market where Petrobras is clearly playing a role despite cutting capex expectations again. ExxonMobil and Equinor are both increasing footprints over the next five years. EMEA will be the other stronghold, driven by stimulus-supported Norway (primarily EQNR and Aker BP), making up almost half of tree orders in the next five years. APAC and Africa will be relatively smaller contributors compared to the aforementioned hotspots, while NAM is in the far backseat with only ~150 trees expected to be awarded over the next five years, per Rystad. Throughout the prior cycle, a heavy reliance was put on brownfield expansions and tiebacks (rightfully so), and just as we were seeing the light at the end of the tunnel last year (i.e. a greater mix of mid/large scale projects), the upstream crash ensued. To put some numbers to it, from 2012-2016, 44% of tree orders were for tieback projects but from 2017-2020, it increased to 54%.

Figure 251: Global Subsea Tree Award Project Scope



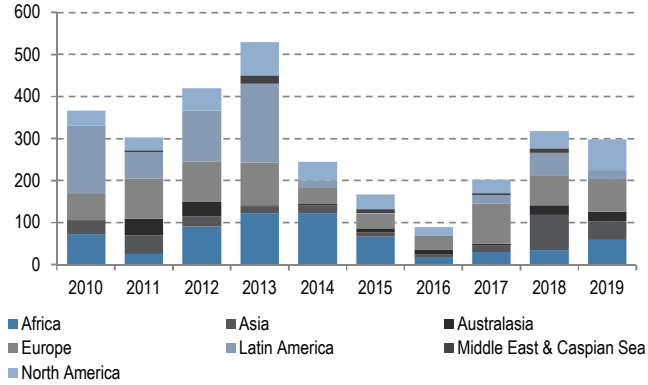
Source: Wood Mackenzie, J.P. Morgan estimates.

Figure 252: Global Subsea Market Operator Mix



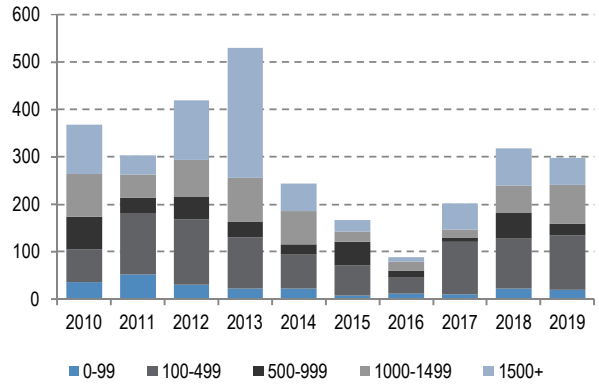
Source: Wood Mackenzie, J.P. Morgan estimates

Figure 253: Subsea Trees by Region



Source: Wood Mackenzie, J.P. Morgan estimates.

Figure 254: Global Subsea Depth Mix



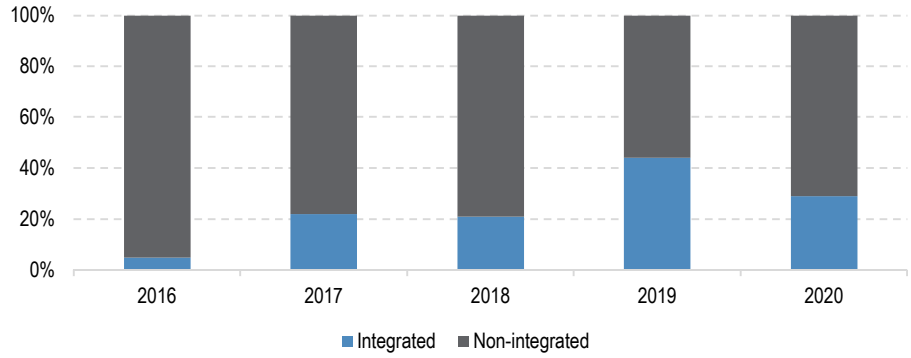
Source: Wood Mackenzie, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Integrated model uptake takes a slight breather but value proposition still there

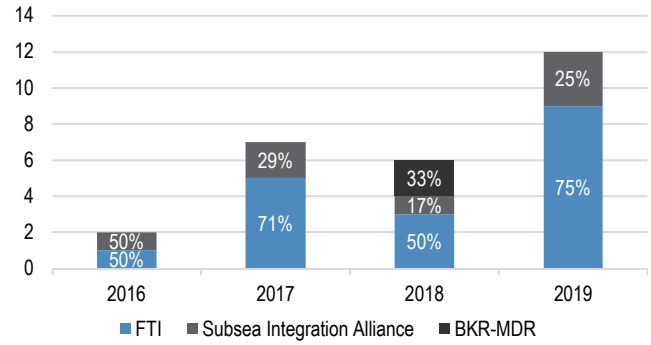
After building strong momentum through 2019, the trend of integrated projects took a pause in 2020 (see below). While FTI won the most integrated contracts in 2020 (as it has four of the last five years), in a year with only ~130 subsea tree awards, OneSubsea surpassed the company for most trees awarded through its integrated contracts. Last year roughly half of FTI's subsea inbound was integrated in nature but these latest data points indicate the mix has moved lower. LatAm remains the exception of the integrated model gaining adoption worldwide; recently Buzios 7 was not an integrated project, for example. IOCs on the other hand have been much more willing to adopt the approach (with some notable exceptions, e.g., XOM).

Figure 255: Mix of Total Awarded Trees



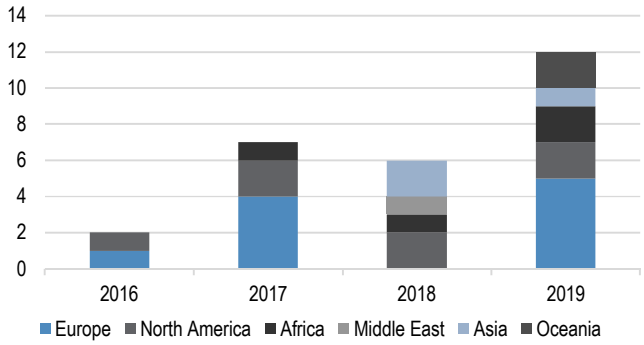
Source: Rystad.

Figure 256: Market Share of Integrated Awards



Source: Wood Mackenzie.

Figure 257: Integrated Awards by Region



Source: Wood Mackenzie.

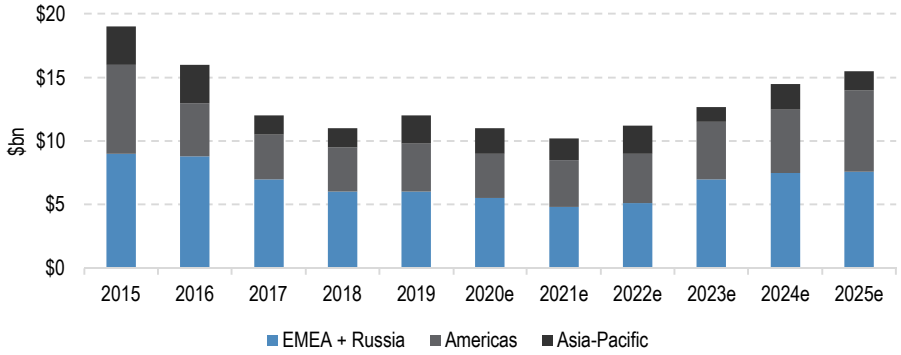
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Total SURF spend through 2025 set to surpass last five years

SURF orders look strong post-2021, driven by the usual suspects

Spending for subsea umbilicals, risers, flowlines and subsea installations fell 7% y/y in 2020 with a similar decline expected in 2021 after only 44 offshore sanctions this year (the lowest in the last 20 years). Assuming ~$55 Brent in 2022, Rystad estimates greenfield SURF awards to grow at CAGR of 8% through from 2021 to 2025, fueled by strength in South America (see below). Growth at that clip could put spend over that five-year span +$3bn higher than from 2016-2020. The relatively healthy Norway market will help to support growth in EMEA. Rystad forecasts +70% of total SURF installations over the next five years in the region will be subsea tiebacks (and +50% in Africa). Petrobras by itself is expected to account for 40% of installations in the Americas as Buzios 5/6 and Mero 3/4 progress. XOM and EQNR are also increasing their presence in the region from a limited base before. Woodside and Santos will be the primary drivers of growth in APAC with the region as a whole considerably less active (only a 1% CAGR through 2025).

Figure 258: SURF Market by Region



Source: Rystad.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Diversifieds

Doubling Down on Adapting to the "New Normal", Which Still Might Mean More of the Same in OFS

Diversified OFS outperformed the sector again; while estimates have reset considerably, OFS earnings torque to the commodity remains asymmetric in our view

Continuing to underperform the commodity in 2020 (for good reason)

In a year SLB, HAL and BKR reached decade (or multi-decade) lows, the now much smaller "Big Three" have underperformed the S&P 500 for the fourth consecutive year (-39% v. SPX YTD). From the diversifieds being down ~70% in March to rallying into December (now "only" down ~25% YTD) with bouts of optimism/pessimism in between (see below), the constant has been the three "large" caps outperforming the other OFS subsectors. Crude and the diversifieds have piggybacked on the vaccine and value trade that started on 11/6 (+28% and +52% since, respectively), but the group has still underperformed the commodity for the fifth year in a row (although not as much this year v. '17-'19 when perceived OFS earnings power took a hit). While the industry can't control the macro, it has done well at navigating it in 2020 both on cost-out and operations, shielding margins better than what was expected earlier in the year. With the group down ~25% YTD, BKR is only down 14% given longer cycle exposure (i.e. int'l, LNG). HAL is hanging in at -18% with SLB the laggard (-43%) amid its strategic pivot.

Figure 259: YTD Performance by Subsector

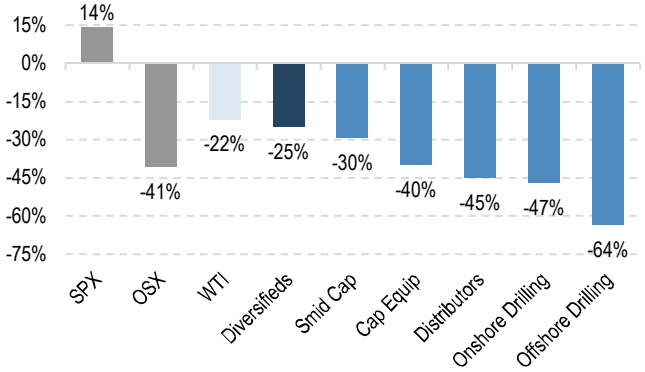


Figure 260: Diversifieds YTD Performance, Indexed

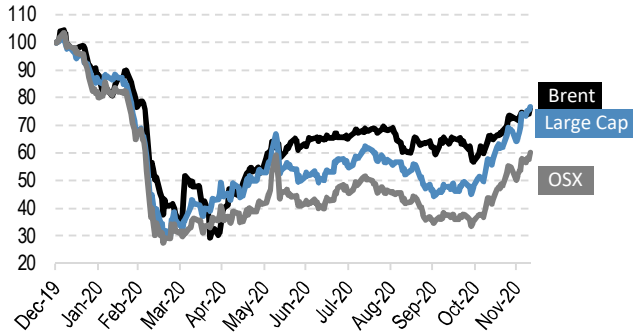


Figure 261: Relative Performance Diversifieds v. WTI (RHS)

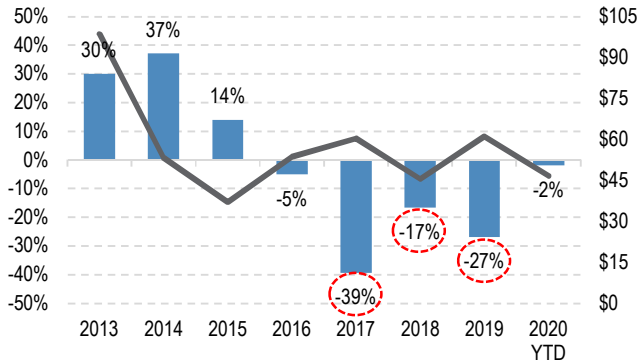
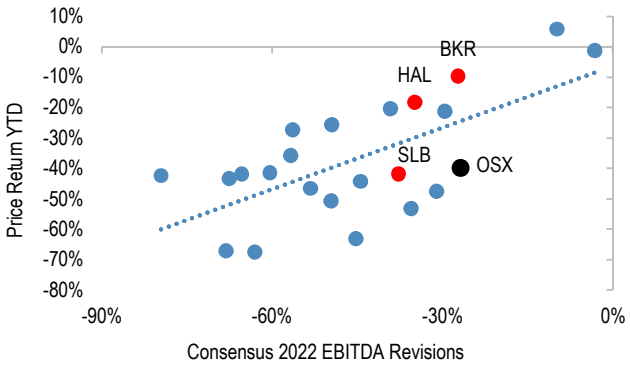


Figure 262: YTD Stock Performance v 2022 EBITDA Revisions YTD



Source for all figures: Bloomberg Finance L.P.

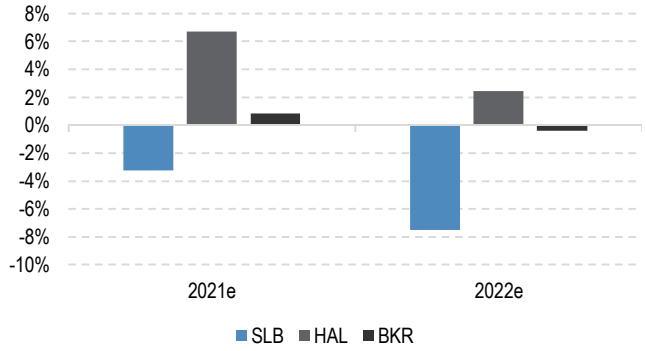
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

2021 estimates look reasonable but 2022 at risk with activity and market expectations pricing in increasingly bullish recoveries

Changes in forward estimates remain a key performance driver

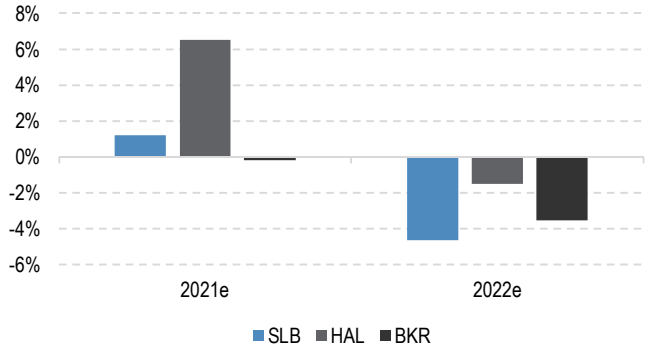
In a year with many moving pieces, FY2 EBITDA revisions were once again a relatively reliable indicator of stock performance (see above). BKR had a strong showing with its longer cycle int'l exposure (and non-OFS end markets). HAL held in surprisingly well despite its higher NAM exposure as investors were quick to price in a return to a normalized NAM onshore cycle. Meanwhile SLB suffered the worst estimate revisions of the three given increasing international mix (thanks to low calorie divestitures) where expectations are increasingly cautious on the capex cycle as the markets expects OPEC/NAM onshore to answer the call on the upstream (as has been our view). While we continue to expect our "watched pot never boils" thesis to continue to play a part in OFS given deflationary pressures, sell side expectations have been meaningfully reset in 2020 compared to prior cycles in our view. Our EBITDA estimates for the diversifieds are slightly above the Street on 2021 (see below) on cost-out execution but in 2022 we expect lackluster ramps in activity to dampen incrementals v. current Street expectations.

Figure 263: JPMe Revenue v. Street



Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

Figure 264: JPMe EBITDA v. Street

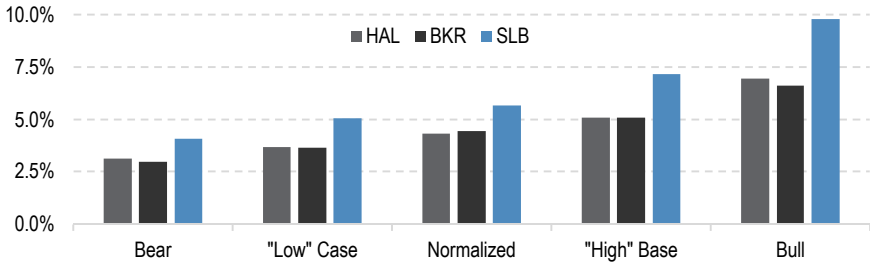


Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

Normalized valuations (already) pricing in too much

Our normalized valuation methodology across our coverage looks to find attractive entry points when the market is pricing in more bearish scenarios, which was clearly the case in March (and close to in October), and then take notice when the market begins to price in overly bullish assumptions. Post-election and amid the vaccine/value rally, the diversifieds seem to be pricing in the high end of our base case for next cycle at +5% yields (see below), keeping us cautious overall. Depending on company-specific factors, we're anchoring our price targets to normalized FCF/EV yields between MSD to HSD as "full" valuations and with that, we think BKR requires a relatively lower FCF/EV yield v. peers given its defensive characteristics (i.e. better balance sheet, larger backlog, diverse end-markets).

Figure 265: Normalized FCF/EV Yield Estimates by Scenario



Source: Company filings, J.P. Morgan estimates.

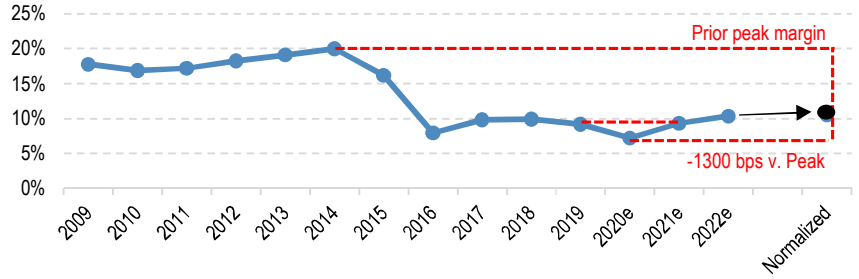
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Prefer BKR over HAL and SLB in 2021 given defensive nature of balance sheet, backlog and end markets (plus energy transition tailwinds)

Schlumberger progressing on proving out margin targets

After setting open-ended targets (e.g. returning to peak int'l and double digit NAM margins), it now comes down to execution for SLB in showing what next cycle can be. With cost-out, divestitures and (hopefully) more discipline on pricing, SLB is doing what it can to improve its trajectory from the trough. We have previously pointed out that while the margin targets are feasible, the unknown is around how much top line needs to shrink to achieve them. SLB recently relayed its expectations to investors that it can reclaim 2019 EBITDA levels ($6.6bn) by recovering only half of the revenue decline in 2020 v. 2019, putting it in-line with 2023 Street revenue but with ~350bps higher margin. We don't expect the market to pay the commentary much heed for now with no timeline attached though the confidence is encouraging. SLB released new financials in November (see our mini-deep dive #3), including its Digital & Integration division, showcasing ~3x higher EBIT margins in 3Q20 compared to the other ~85% of the company. While we think Digital can deliver relatively attractive growth and help on margins, we remain cautious on the international E&P capex cycle and the potentially offsetting impacts of underlying deflationary pressure on core OFS offerings.

Figure 266: EBIT Margin Targets

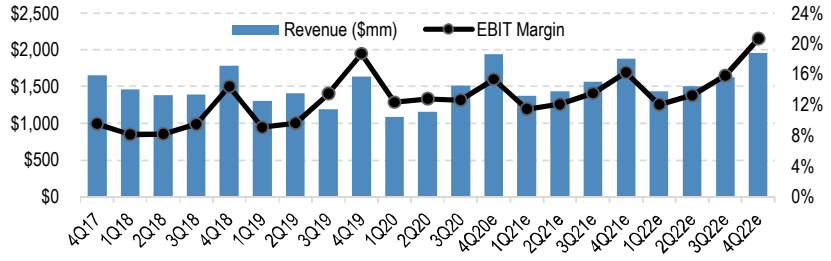


Source: Company filings, J.P. Morgan estimates. Note: SLB's prior commitment was NAM/Int'l pre-corporate and ex-Cameron. With the new segmentation, we're adjusting to companywide margins.

Baker Hughes still an advantage pick in this downturn

Even with the most recent oil-beta rally, BKR is outperforming SLB/HAL YTD by 29%/4% (helped by longer and later-cycle mix), a trend we think will continue as the recovery underwhelms. We expect BKR's path to higher earnings cycle over cycle to continue to crystalize, giving it an edge v. OFS peers. While its OFS and OFE segments will likely match the E&P capex cycle but benefit from strong cost-out (similar to SLB/HAL), BKR's differentiators lie elsewhere. The expectations for TPS orders and margins seem achievable in our view and skepticism around LNG's position in the evolving energy mix seems overblown this year. BKR's positioning in new energy is firming up in its turbine business, carbon capture offering and emission reduction/monitoring technology for its large installed base. If BKR can deliver on our estimated ~$1.1bn in free cash flow in 2021 (v. ~$1.0bn Street), it should shore up investor confidence (and help to mitigate the GE overhang).

Figure 267: TPS Revenue and Margin Trajectory



Source Company filings, J.P. Morgan estimates.

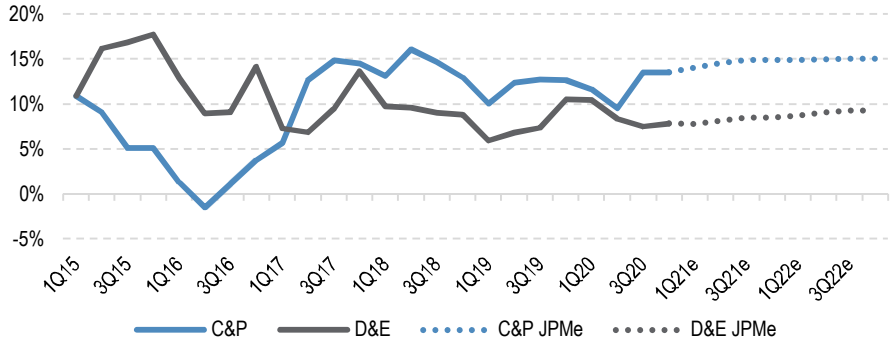
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

HAL has been successful in delivering on strategic priorities, but we think the stock faces a high hurdle to achieve outperformance in 2021 after the strong 4Q20 rally

HAL's strategic shift presents better runway for C&P margin; D&E to lag

Halliburton showed that it can "walk the walk" on cost control and emphasizing value over volume in NAM C&P in 2020. The company successfully completed ~$1bn in cost reductions in the past year, much of which centered on NAM frac, and oriented away from a bulk of the "low-calorie" work in C&P. The result has been a fairly rapid recovery in C&P EBIT margin (asset write-downs helped too, of course), which returned to +13% in 3Q20 for the first time since 2018 after hitting a trough of <10% during the depths of the downturn in 2Q20. We believe through the NAM completions recovery in 2021 and the continued ramp up of its "Halliburton 4.0" suite of digitally-enabled technology HAL can further improve C&P profitability and approach its ~15% "normalized" EBIT margin bogey by 4Q21. D&E margin looks more challenged to us however, as we anticipate a slower recovery in international activity compared to NAM, presenting fewer growth opportunities for the international-oriented segment. As such we expect D&E EBIT margin to be range bound at 7-9% in 2021. Though capital efficiency efforts should help Halliburton deliver solid FCF in 2021 in our view (JPMe ~$850mm), investors have been eager to reward the stock for these initiatives and an improved NAM outlook, leaving us cautious on the shares as expectations look prone to moderation in 2021.

Figure 268: HAL EBIT Margin by Segment



Source: Company filings, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Capital Equipment

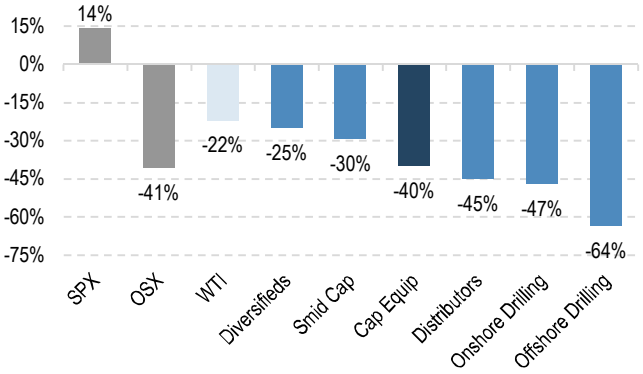
Orders and Margins Have Troughed, but Capital Scrutiny and Underwhelming Activity Pose Headwinds

Idiosyncratic opportunities in capital equipment but 2021 looking to be a tough slog

Finishing in the middle of the pack

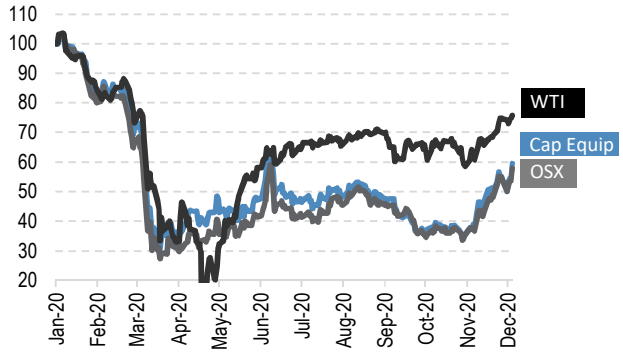
Capital Equipment stocks performed relatively in line with the OSX this year (down -40% v. OSX -41%). After the March bottom, the group bounced back relatively well, but as the depth and duration of the downturn was better understood with very weak 2Q/3Q orders (see next page), performance has fallen back in line. With relatively high international mix, performance was also likely held back with a deteriorating global spend outlook in 2021 and beyond. Even when excluding OIS's lackluster performance, the group underperformed the smid-caps by ~10% YTD as offshore floundered and equipment revisions weren't spared. FTI has been most shielded by negative estimate revisions v. equipment peers (see Figure 272), but its shares continue to take a beating ahead of the pending spin. We think a resolution now serves as a positive catalyst is still on its way. On the other side of the trend line, TS, DRQ and WHD performed better v. the peer average with the latter two being part of our defense/NAM offense barbell approach (i.e. backlog-driven stocks + cheap NAM completion exposure, both offering strong balance sheets).

Figure 269: YTD Performance by Subsector



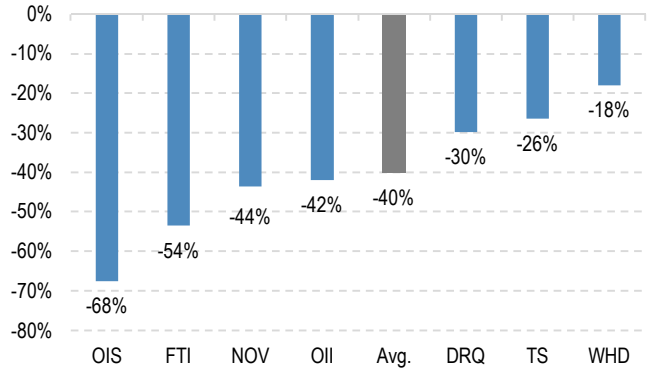
Source: Bloomberg Finance L.P.

Figure 270: Capital Equipment YTD Performance, Indexed



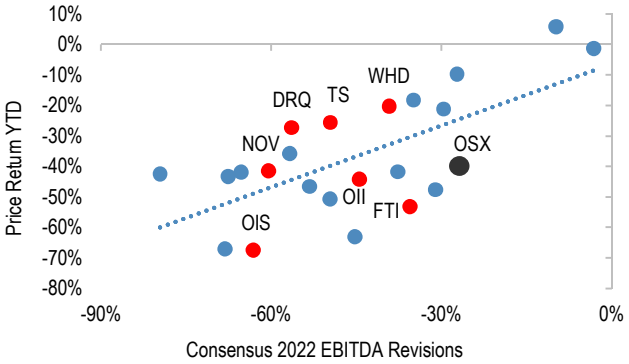
Source: Bloomberg Finance L.P.

Figure 271: YTD Stock Performance



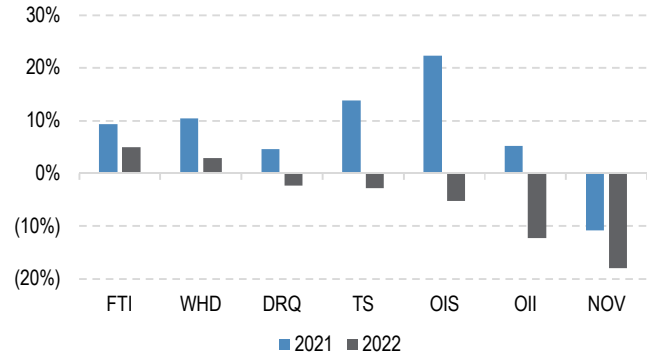
Source: Bloomberg Finance L.P.

Figure 272: YTD Stock Performance v. 2022 EBITDA Revision



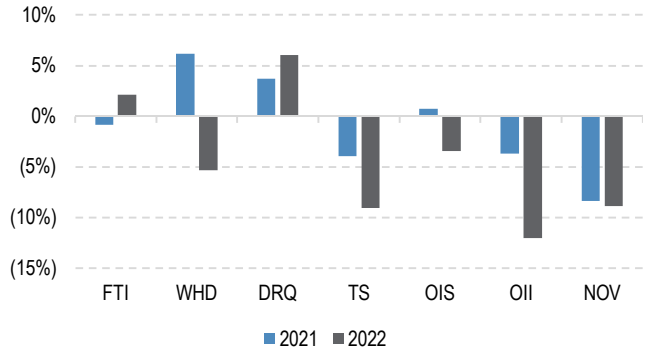
Source: Bloomberg Finance L.P.

Figure 273: JPMe EBITDA v. Street, Sorted by 2022



Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

Figure 274: JPMe Revenue v. Street

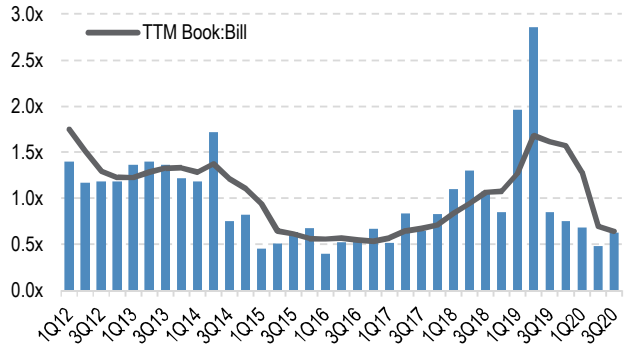


Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

2022 Street estimates look optimistic with orders to remain challenged in 2021

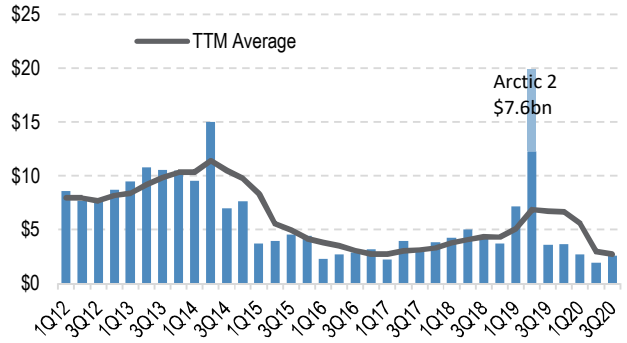
Consensus revenue estimates for capital equipment in 2021 seem to be in line with our estimates on average, but we see some pockets of downside in 2022 as orders likely disappoint next year, especially in offshore markets (e.g., OII, NOV). On average, we are above the Street on 2021 EBITDA given the theme of cost-out across OFS, helping to rebase margins higher after strong 3Q20 prints (and some "law of small numbers" impacts). With vicious pullbacks in E&P spend, 2Q20 represented the bottom in orders, at just under 0.5x book:bill across our coverage. We expect orders to continue to trend higher post 3Q20's bounce back but model book:bills remaining around ~0.8x in 2021 and 2022 with capital austerity making its usual rounds through the supply chain. Per Figure 275, TTM book:bill remained below 1.0x from 1Q15 through 2Q18 (fourteen quarters) but the destocking headwind from last cycle is not as strong this time around. We think NAM orders will show strong sequential growth in the next few quarters (off a low base) as activity ramps in 1H21 but from there we a more cautious stance on the recovery is prudent.

Figure 275: Capital Equipment Aggregate Book:Bill Ratio



Source: Company reports, J.P. Morgan estimates.

Figure 276: Capital Equipment Aggregate Orders ($bn)



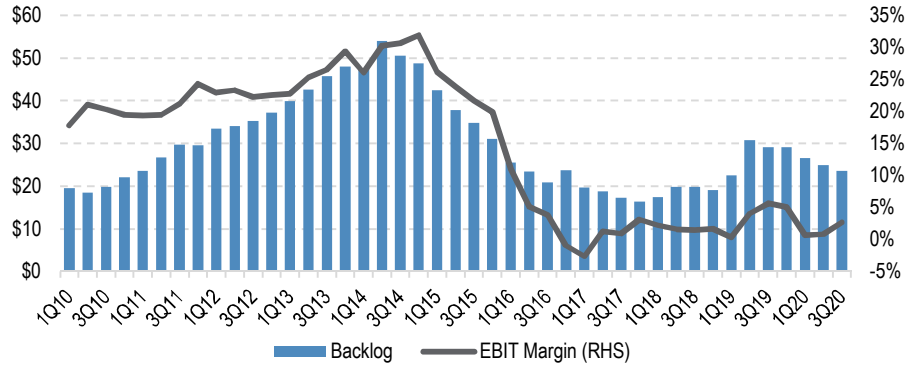
Source: Company reports, J.P. Morgan estimates.

Margins largely outmatched COVID-19 disruptions

As the group's backlog deflated through 2015-2018 (see above), operating margins went with it, likely further hampered by negative NAM/int'l mix. In 2019 margins were beginning to improve from breakeven levels, then the pandemic sent them backwards. With global disruptions delaying projects and impacting manufacturing, operations and margins held in relatively well, and the intense cost-out execution has helped to set what seems like a mid-2020 floor.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 277: Group Backlog ($bn) v. Operating Margins

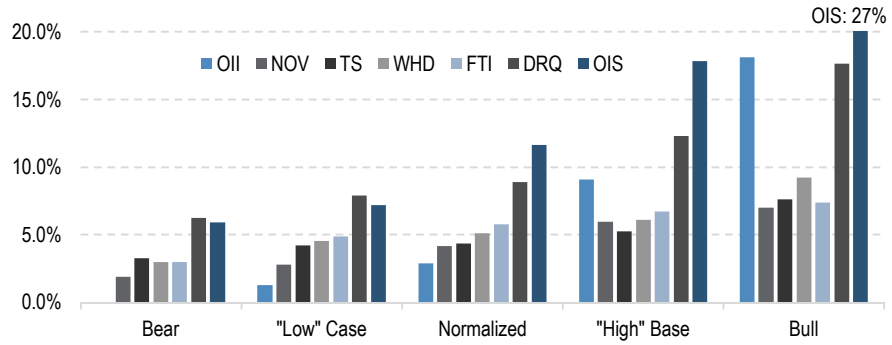


Source: Company reports, J.P. Morgan estimates. Note: Excluding outlier OIS in EBIT margin average in 2Q20/3Q20 (-20%/-18%).

Normalized valuations highlight idiosyncratic opportunities

The rally over the last month has been a tide that has lifted all boats, and relative to the recovery the market seems pricing in, we are most cautious on OII and NOV. The former is highly levered to the disadvantaged offshore drilling market and the latter's Street estimates have further downside in our view. FTI remains in "spin purgatory", underperforming the OSX by 13% YTD given limited clarity on the timing and outcome of the spin of Technip Energies, thus investors have shown limited appetite to step in prematurely. With FTI looking cheap on a normalized basis (see below) and trading at ~4.5x on 2022 JPMe EBITDA, it's one of our top picks. We expect the spin to unlock value for shareholders and FTI's strong energy transition offerings (e.g. LNG, hydrogen, biofuels) could allow it to capitalize on "green multiple" arbitrage. After being the best performer in our coverage last year, DRQ continues to stand out with a dislocated valuation relative to its assets and clean balance sheet. To some extent the stock will be held back by deepwater headwinds, but with a strong cash balance, new technology offerings and a management team with a solid operational track record, we think there is room for mean reversion in 2021.

Figure 278: FCF/EV Yield Estimates by Scenario, Sorted by "Normalized" Yield



Source: Company filings, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Small-Mid Cap Services

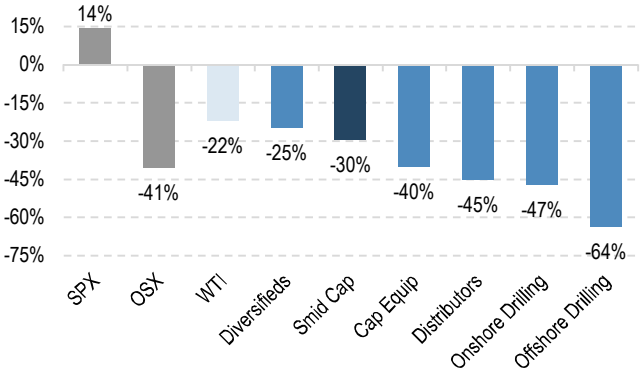
Good Upside Optionality for the Pumpers,

Strong results from NESR +7% YTD and LBRT (+1% YTD) lifted smid-caps above the OSX in 2020 (-30% v. -41% YTD)

Smids end 2020 among our better performers, helped by a few "small" outliers

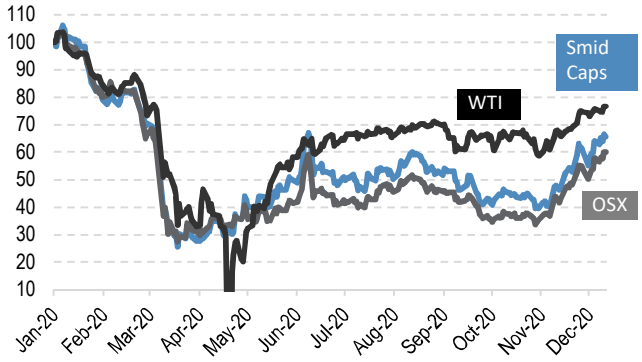
The smid-caps were the second-best performing group in our coverage in 2020 at -30% YTD (v. OSX -41%), trailing only the diversifieds (-25% YTD), though with material dispersion. The group was aided by the two top-performing stocks in OFS, NESR (+7% YTD), which has a unique MENA footprint that allows for organic growth, and LBRT (+1% YTD) which benefited from a well-received deal to acquire OneStim from SLB. On the opposite end of the stock dispersion range, NINE was the worst performer in our coverage this year (-70% YTD), weighed down by already elevated leverage heading into the downturn, while the energy distributors MRC and DNOW (-50% and -41% YTD) also lagged due to declining demand across revenue streams despite the counter-cyclicality of their cash flows. Among the completions-oriented names, the market has shown willingness (lately) to give credit to the pressure pumpers for a NAM frac recovery in 2021+. As such, Permian-focused PUMP has performed relatively well (-28% YTD), but NEX has lagged on a perception it "missed out" on the OneStim deal; we think such concerns regarding its legacy-CJ fleets are overdone (as we contest). Going into early 2021 we favor NAM completions with solid balance sheets as part of our offense/defense barbell.

Figure 279: YTD Performance by Subsector



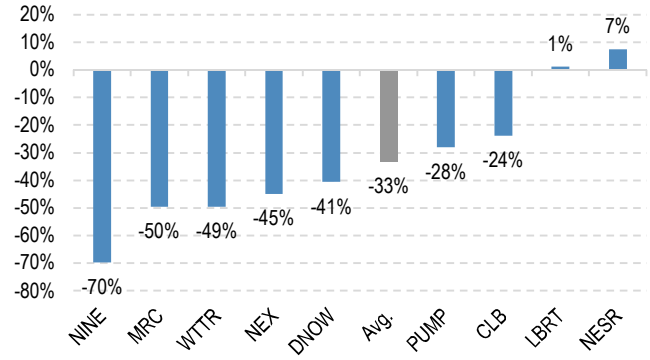
Source: Bloomberg Finance L.P.

Figure 280: Capital Equipment YTD Performance, Indexed



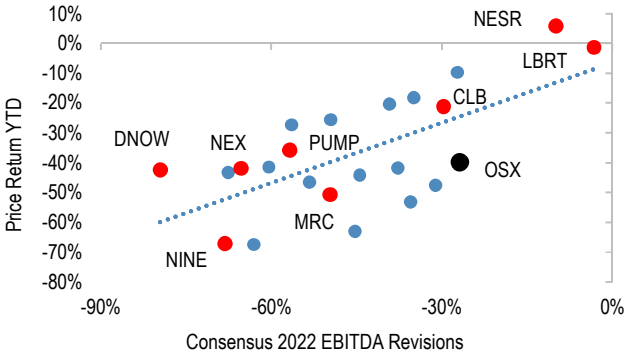
Source: Bloomberg Finance L.P.

Figure 281: YTD Stock Performance



Source: Bloomberg Finance L.P.

Figure 282: YTD Stock Performance v. 2022 EBITDA Revision



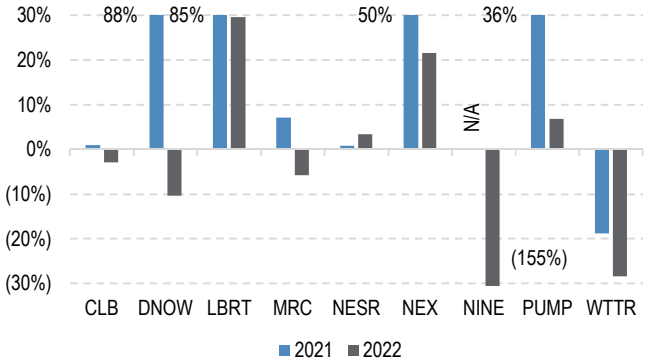
Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Modeling upside to Street estimates for the pumpers, others flat or lower

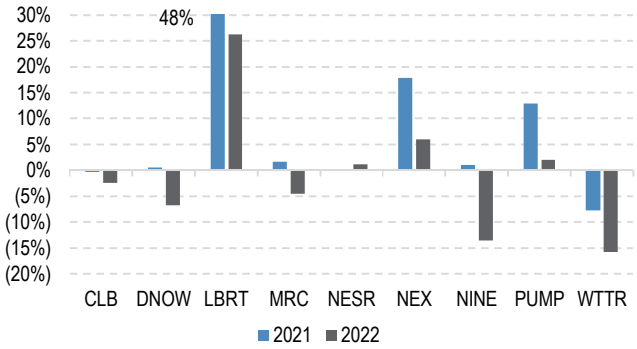
Compared to Street estimates, we see the most scope for upside revisions to forward expectations among the pure-play pressure pumpers (LBRT, NEX, PUMP), as these companies are most likely to benefit from operational leverage in an improving demand environment. Of course within this group the "law of small numbers" must be kept in mind as it creates some outsized discrepancies v. consensus (e.g. JPMe 2021 EBITDA for NINE is -$4mm v. Street -$2mm). LBRT also presents outlier results as we assume some of our peers are not including OneStim in estimates until the deal closes (guided for YE20). For CLB and NESR our outlook aligns relatively closely with consensus, while for MRC, DNOW, and WTTR we are biased lower than the Street in 2022 as we see less potential for upside capture during the recovery for these companies.

Figure 283: JPMe EBITDA v. Street, Sorted by 2022



Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

Figure 284: JPMe Revenue v. Street

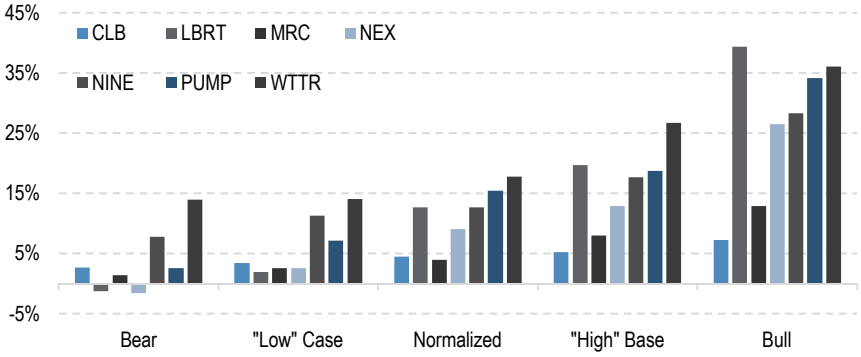


Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

FCF/EV yields support our offense preference for the pumpers over drillers

Comparing "normalized" FCF/EV yields we again see the pure-play pressure pumpers as advantaged in our view, with relatively cheaper valuations. In our high base and bull cases we think these companies can grow FCF rapidly in stronger activity environments. While such outcomes may be unlikely to materialize in 2021/2022, the outlook still supports our favoring of these names as part of the offense strategy in our view to capitalize on potential upside. Otherwise, we primarily stay defensive. Yields among other smid-caps look more full to us on a normalized basis, such as for CLB, which has benefited from a strong run up in the most recent rally (+89% since 11/6 v. OSX +62%).

Figure 285: FCF/EV Yield Estimates by Scenario, Sorted by "Normalized" Yield



Source: Company filings, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Land Drillers

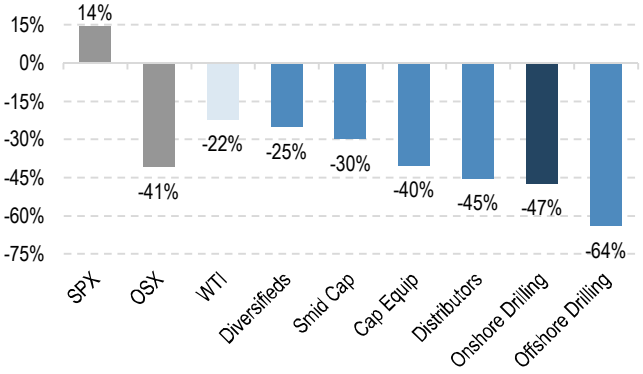
2020's Underperformance May Be Hard to Undo at Current Valuations Despite Rising L-48 Rig Demand

Land drillers can look forward to a better L-48 demand environment in 2021, but we see better upside among completions-levered stocks

Land drillers' 2020 performance places near the bottom of our coverage group

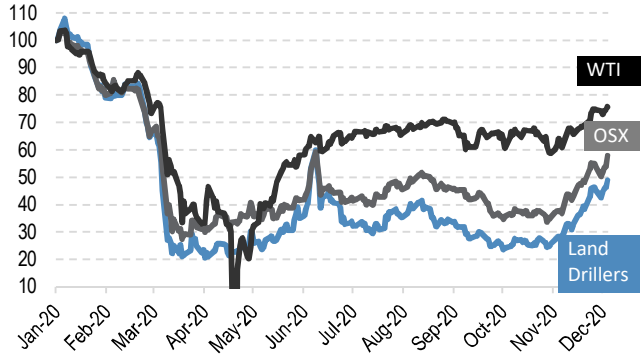
The land drilling stocks performed worse than the overall group in 2020, falling -47% YTD v. OSX -41%. Within the sub-sector, dispersion was surprisingly narrow, with HP performing the best of the group (-45% YTD), while UW-rated peers PTEN and NBR lagged (-47% / -51% YTD, respectively). The land drillers fell to a deeper trough than the OSX in the spring sell-off, weighed down by investor fears of a potential bankruptcy for balance sheet-constrained Nabors, which was down as much as -93% YTD in April. In the ensuing months, prospects for the group brightened on higher crude prices and an improved NAM land outlook, and for NBR in particular, prudent balance sheet management to buy additional runway for debt repayments led the stock to largely realign its performance with peers. Going forward, we see an improving demand environment for land drillers as U.S. operators need to put more rigs to work in order to reach 2021 production targets. However, with pricing recovery likely muted, we see more upside optionality among our completions-oriented coverage with high operating leverage (i.e. PUMP, NEX).

Figure 286: YTD Performance by Subsector



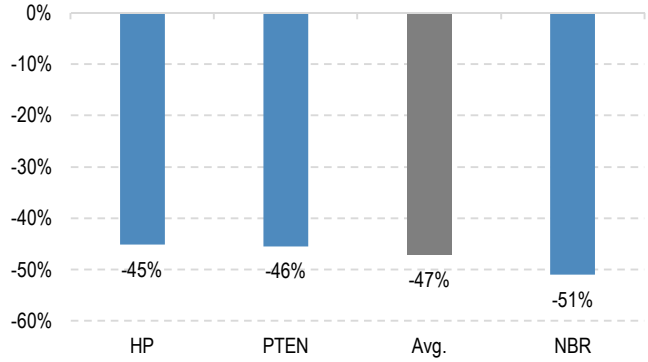
Source: Bloomberg Finance L.P.

Figure 287: Land Drillers YTD Performance, Indexed



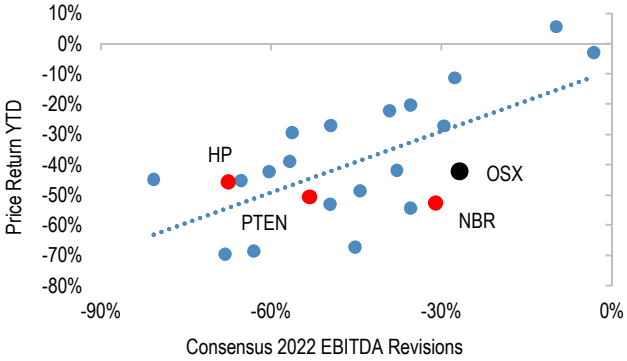
Source: Bloomberg Finance L.P.

Figure 288: YTD Stock Performance



Source: Bloomberg Finance L.P.

Figure 289: YTD Stock Performance v. 2022 EBITDA Revision



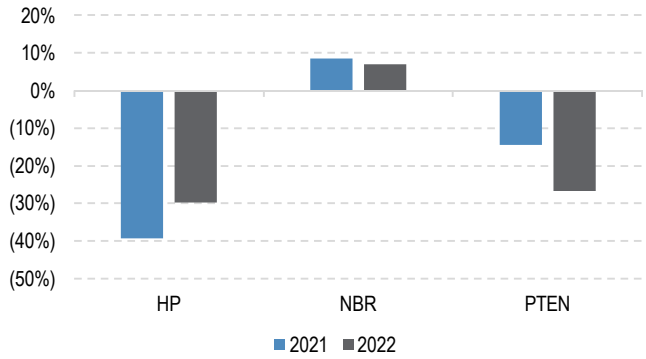
Source: Bloomberg Finance L.P.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Street EBITDA estimates look too high for land drillers, revenue mixed

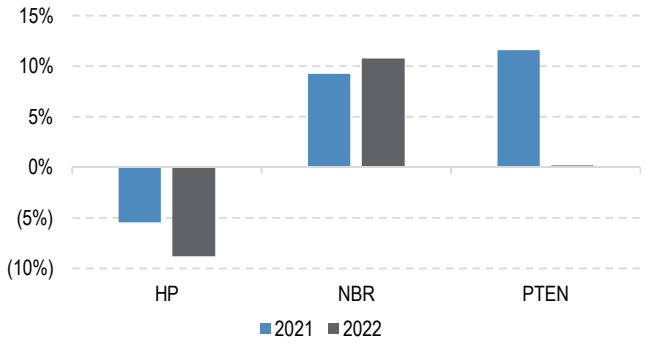
Generally consensus EBITDA estimates appear overly optimistic for the land drillers in 2021/2022, evidence by our modeling of HP and PTEN 2022 EBITDA -25-30% below the Street (while NBR is more in-line). We think many sell-siders and buy-siders alike have been quick to assign credit for a fairly strong recovery in NAM drilling over the next few years. While we certainly anticipate a buildup in the rig count in 2021 (JPMe L-48 average 365 v. 4Q20 291), once operators reach sustaining levels, we think further growth will be challenging. As such, we model the 2022 rig count only growing ~15% y/y. Additionally, we are cautious on pace of land drilling margin expansion in the coming years, as contracts priced in last cycle roll over to leading-edge rates that generally price super-spec rigs in the high-teens $k/d range (v. low-to-mid $20k/d last cycle). Technology additions and new performance-based contracts may offer some offset, but overall we think the Street's margin expectations for the group are likely to slip lower early in 2021.

Figure 290: JPMe EBITDA v. Street, Sorted by 2022



Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

Figure 291: JPMe Revenue v. Street

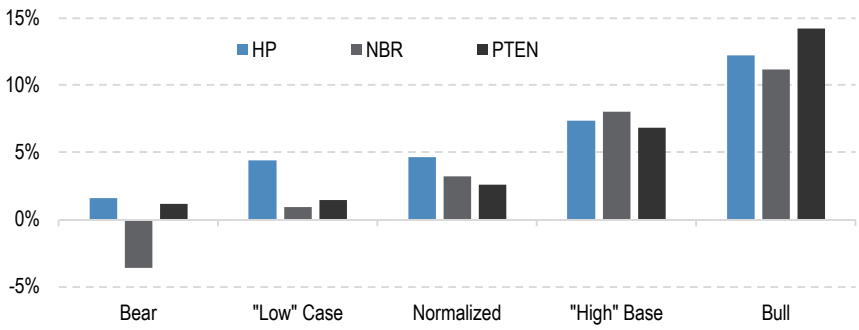


Source: Company filings, J.P. Morgan estimates, Bloomberg Finance L.P.

Normalized FCF/EV implies fairly full valuations for land drillers

Following the recent vaccine-led rally, valuations across the land drillers (and our broader NAM-coverage) express an increasingly optimistic view for NAM through-cycle demand in our opinion. Based on our macro expectations and company modeling, we see FCF/EV yields for the land drillers expressing more or less full valuations currently. We maintain HP (N) as our relative favorite in the group, though with a base case FCF/EV of ~5% we think absolute upside may be challenging in 2021. Meanwhile we remain cautious on PTEN (UW) on concerns around upside capture in the NAM recovery, as well as on NBR (UW) due to what will likely be insufficient FCF generation to de-risk the balance sheet this cycle.

Figure 292: FCF/EV Yield Estimates by Scenario, Sorted by "Normalized" Yield



Source: Company filings, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Offshore Drillers

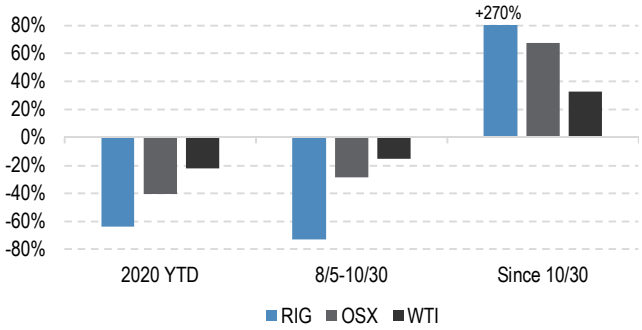
Utilization Without Compensation Continues Until Eventual Demand Meets Properly Rationalized Supply

RIG remains one of our top Underweight picks

And then there was one: contractors navigating restructuring

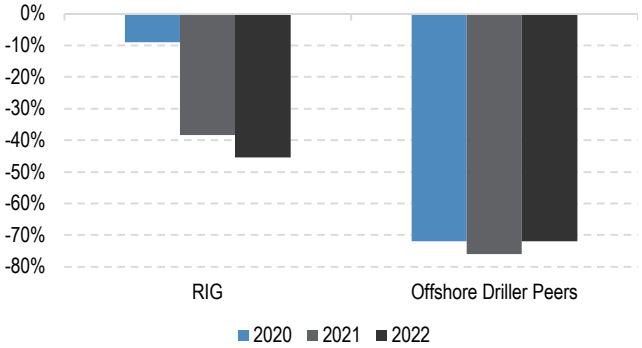
Heading into 2020, we were skeptical of what we considered overly optimistic expectations (as usual) for a recovery in the offshore driller market. Cue a global pandemic which severely disrupted offshore rig operations (comparable to cruise ships without entertainment) and cancelled or pushed out many programs. This downturn prompted many offshore driller bankruptcies (e.g. DO, NE, VAL, SDRL, PACD), and while some are preparing to emerge soon, RIG is going through its liability management exercise. From the announcement on 8/5, RIG shares fell -73% through 10/30 and have since been swept up in another value rotation trade (more than doubling since, see below). RIG's backlog and ability to contain costs and support margins (see Figure 295) have kept nearer term Street estimates relatively shielded but 2021/2022 have been cut considerably with the long-awaited offshore inflection pushed out another two years (see Figure 294). Our HY Credit colleagues think RIG can make it to 2022/2023, but we still think restructuring risk in 2021 is on the rise given challenged access to capital amidst a deteriorating offshore market outlook and potential strategic rationale with most peers in restructuring.

Figure 293: Transocean Price Performance v. OSX and WTI



Source: Bloomberg Finance L.P. Note: RIG announced private exchange agreement on 8/5.

Figure 294: Offshore Driller EBITDA Revisions YTD



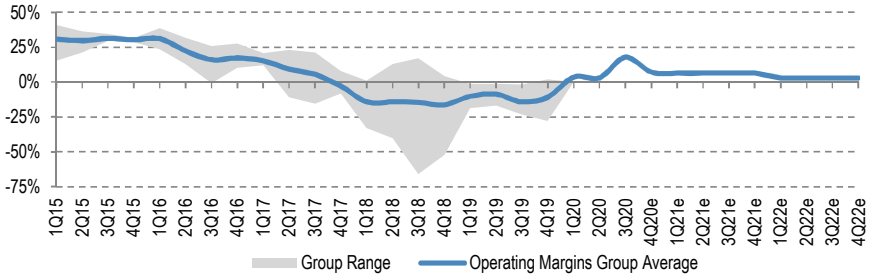
Source: Bloomberg Finance L.P. Note: Peers include Diamond Offshore, Noble Corp and Valaris (all non-covered).

Demand pushed out (and lower), but supply rationalization is encouraging

The offshore rig market remains oversupplied, though solid progress towards increased rig scrapping has been made since March. Available floater supply has dropped considerably y/y (see below), yet there is room for more in our view as rigs roll-off in the coming quarters onto a bleak market and newbuilds continue to be pushed or abandoned entirely. On the demand side, with a depressed yield curve we expect operators to employ heightened capital discipline with cash use priorities shifting to the balance sheet, delivering shareholder returns and for household offshore names, increasingly shifting spend to green energy. The marriage of supply and demand dynamics in this market is not conducive to materially better dayrates, as fierce competition will likely lead to disappointing fixtures in our view (for the relatively few that come through).

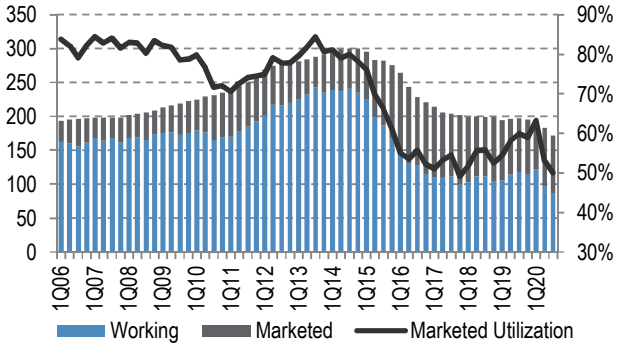
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 295: Historical and JPMe Offshore Driller Margin



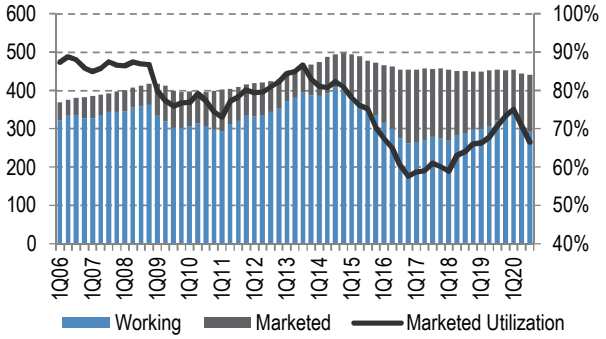
Source: J.P. Morgan estimates, Company data. Note: Group includes Diamond, Noble, Transocean and Valaris through 2019, followed by estimated Transocean annual average through 2022.

Figure 296: Historical Floater Utilization



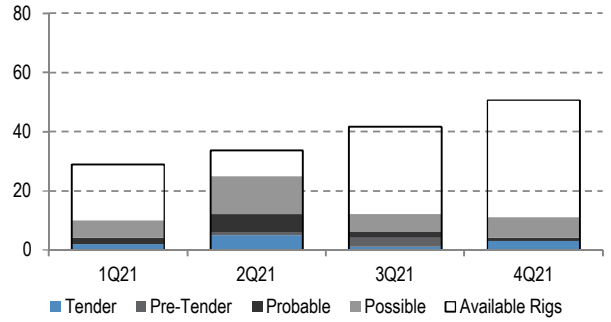
Source: IHS-Petrodata.

Figure 297: Historical Jackup Utilization



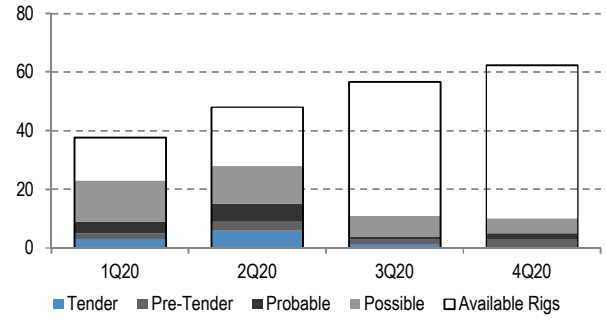
Source: IHS-Petrodata.

Figure 298: Current Open Demand v. Available Drillships



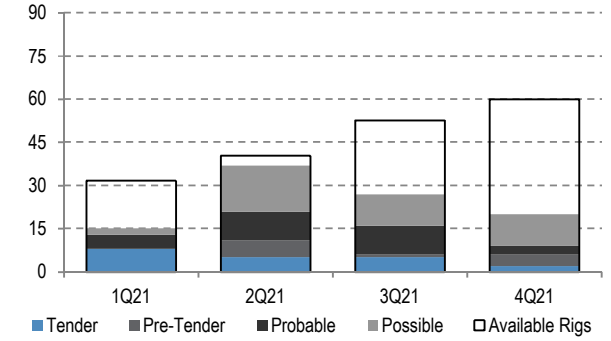
Source: IHS-Petrodata, J.P. Morgan estimates.

Figure 299: Open Demand v. Available Drillships Last Year



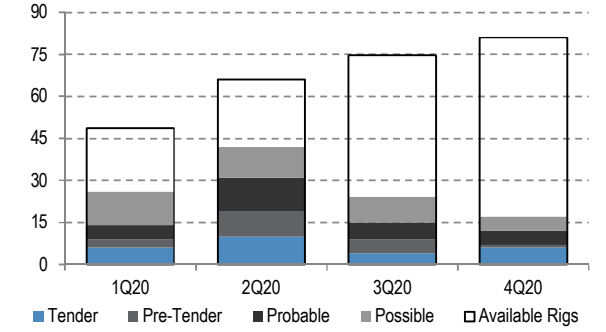
Source: IHS-Petrodata, J.P. Morgan estimates.

Figure 300: Current Open Demand v. Available Semis



Source: IHS-Petrodata, J.P. Morgan estimates.

Figure 301: Open Demand v. Available Semis Last Year



Source: IHS-Petrodata, J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Balance Sheet Monitor

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Balance Sheet Monitor

Pandemics, Price Wars, and Presidents: A Colorful 2020

2020 has been a year marred by generational decline, uncertainty and unprecedented efforts to structurally improve cost structures

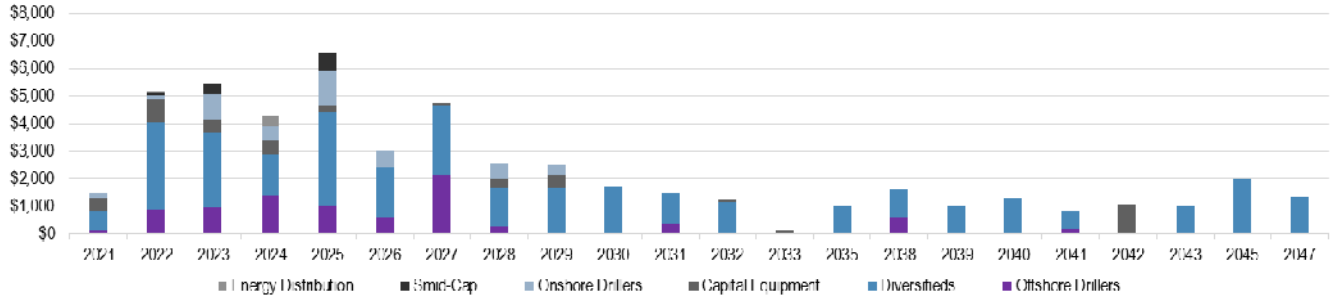
Since early March we have said what matters most for OFS companies is not the depth of the downturn but the duration in which the sector is forced to reckon with lower levels of activity and profitability. While both activity and stock prices have bounced from generationally low bases, we continue to view the path to recovery as a choppy one apt for disappointment compared to the increasingly optimistic assumptions being priced in. With the path to normalization of credit metrics pushed out and earnings power seeming impaired cycle/cycle for the second consecutive cycle, the outlook doesn't bode well for the sector's upcoming maturities (see below), but in general the market has been supportive of refinancing.

In this section we include snapshots of key balance sheet and capital structure metrics for each company in our coverage, including: current cash and liquidity available; a debt maturity waterfall; debt details for the entire capital structure

After fairly resolute access to equity and especially debt markets in 2016-2018, we've witnessed a significant reduction in appetite for energy paper, not least in OFS. 2020 drastically exacerbated this trend through mounting ESG concerns, oil price conflicts, and of course the COVID-19 sponsored market disruption. These events have fundamentally changed investor sentiment surrounding the OFS industry. Specifically, our colleagues covering Alternatives report declining costs of capital amid the flood of capital towards renewable power sources. Conversely, given poor equity performance and mounting ESG demands, the cost of capital for "old" energy has steadily risen, reinforcing investors' trepidation to oil & gas exposure.

Further shaping the future of energy, President-elect Biden has staked a claim on fostering the growth of renewables and reducing carbon emissions. Getting ahead of the energy-transition curve, a few enterprising companies within our coverage have positioned to capitalize on green energy sources, such as hydrogen, CCUS and yes, LNG. If the transition has been accelerated by the pandemic and further exacerbated investors' frustration with upstream returns, we expect the impact on U.S. activity to be modest, barring a surprise outcome catalyst in the upcoming Georgia run-off.

Figure 302: JPM Oil Services & Equipment Coverage: Cumulative Debt Maturities ($mm)



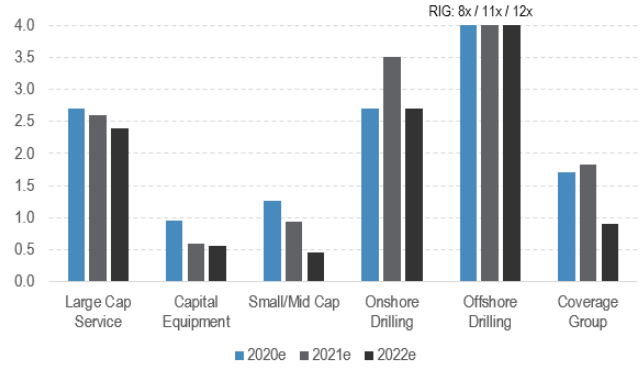
Source: Company reports and J.P. Morgan estimates.

As Restructuring Cycle Accelerates, Fewer Risks Remain

Looking into activity levels, 2020 saw a -60% decline in NAM rig counts from February highs of 796 to July lows of 296. This was echoed by international rig counts with an approximate -40% decline during the same period. In this environment our coverage has been quick and effective in taking cost out, providing a balance sheet buffer via FCF in 2020, though with little improvement in 2021, as shown below. While OFS will continue to be squeezed by operators, internal focus on cost savings and cash will allow for some to de-lever as activity picks up (post-2021). The biggest risks among what's left of our coverage remains offshore and int'l drilling with most offshore drillers in restructuring while RIG and NBR continue to walk down the liability management path.

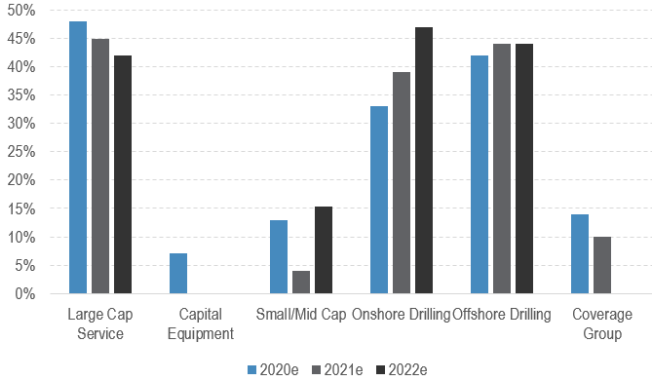
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 303: JPMe Net Debt-to-EBITDA by Subsector 2020e-2022e



Source: Company reports and J.P. Morgan estimates. Note: Excluding Energy Distribution with 12.7x/3.7x/-14.5x in 2020/2021/2022.

Figure 304: JPMe Net Debt-to-Capital by Subsector 2020e-2022e



Source: Company reports and J.P. Morgan estimates. Note: Excluding Energy Distribution with -22%/-21%/-29% in 2020/2021/2022.

Elevated debt levels *slowly* normalizing, looking to 2023…

Looking out over the near-term horizon, the majority of debt coming due is attributable to the diversifieds. Specifically, by 2025, SLB has ~$6.1bn in notes due, along with ~$3.7bn for HAL, but the capital markets remain supportive of the "Big" Three in general. We expect a combination of debt reduction and term extensions as modest levels of post-div FCF are applied to the balance sheet. We continue to prefer BKR's relative defensiveness with longer cycle backlog and a stronger balance sheet (net leverage of 1.5x/1.3x in 2021/2022) and a relatively advantaged path to higher earnings cycle/cycle.

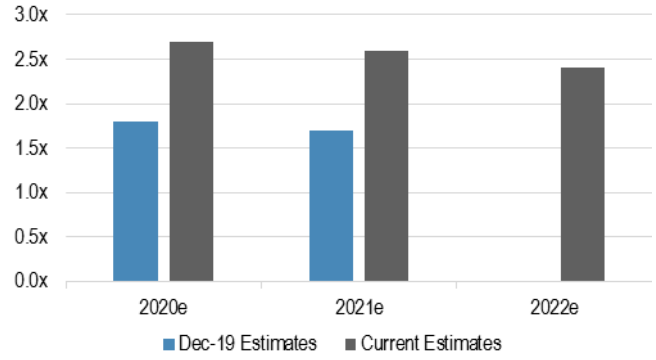
Transocean: the last offshore driller still standing

This year helped to accelerate offshore drilling restructuring which we have always expected to arrive, pandemic or not, given our thesis that any upcycle would lack in magnitude and duration to generate enough FCF to clean up over-levered balance sheets. Diamond Offshore filed in April, followed by Noble in late July, and finally Valaris in August (as well as SDRL and PACD). Assuming legal complexities around the ongoing liability management exercise don't dry up liquidity further, our High Yield Credit colleagues think RIG has the financial wherewithal to get through to 2022/2023. This is further reinforced by RIG's ~$1.3bn in cash on hand and an undrawn revolver (which matures in 2023), but it has a few smaller maturities in 2021/2022, followed by ~$1.0bn/~$1.4bn for 2023/2024 in addition to sticky newbuild commitments. Given our dismal view on the offshore drilling market and RIG's main competitors are likely sizing up consolidation paths while on hiatus from the equity market, we think restructuring risk will loom larger through 2021 and thus remain Underweight.

Nabors: still fighting the good fight

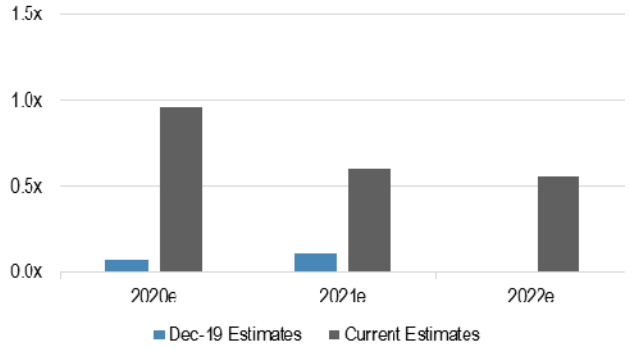
Similar to RIG, Nabors continues to execute on its own debt exchanges, with ~$380mm (~28% of eligible notes) being tendered and NBR recently announced another ~$32mm completed. The exchanges are in-line with expectations we laid out regarding Nabors' priming options over the summer, and overall we think these are prudent balance sheet management measures that help buy the company time to reduce its leverage. However, given our outlook for the cycle and negative view on the cash generation ability of NBR's international business, success is far from guaranteed, and we think it will be difficult for value to accrue to equity holders.

Figure 305: Diversifieds JPMe Net Debt-to-EBITDA



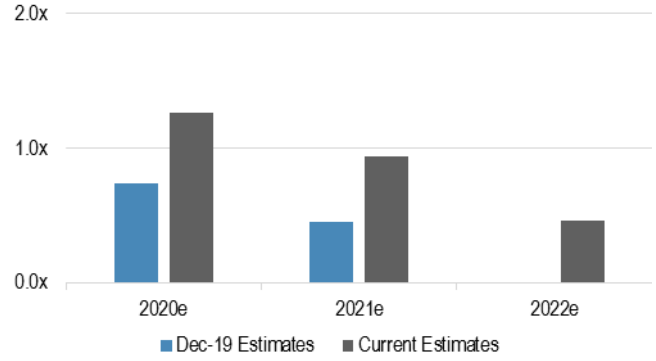
Source: Company reports and J.P. Morgan estimates.

Figure 306: Capital Equipment JPMe Net Debt-to-EBITDA



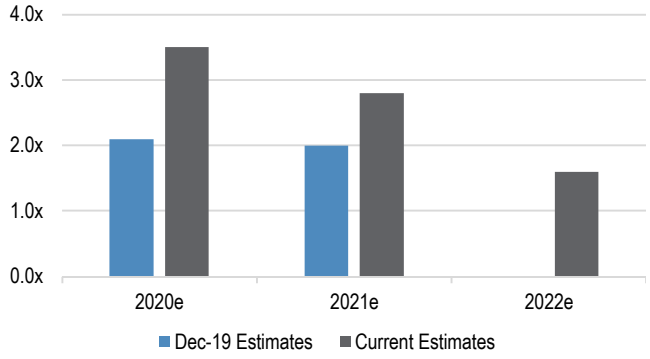
Source: Company reports and J.P. Morgan estimates.

Figure 307: Smid-Cap JPMe Net Debt-to-EBITDA



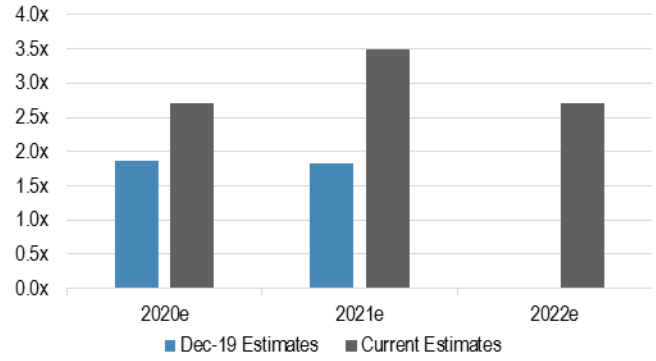
Source: Company reports and J.P. Morgan estimates.

Figure 308: Energy Distribution JPMe Net Debt-to-EBITDA



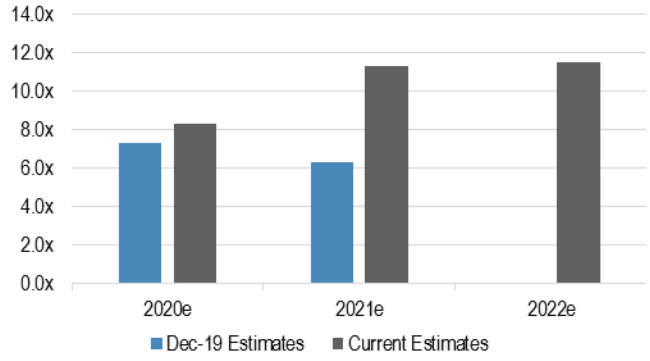
Source: Company reports and J.P. Morgan estimates. Note: chart shows MRC only; DNOW has a net cash position of ~$325mm on JPMe EBITDA of -$15mm/-$2mm/$22mm in 2020/2021/2022.

Figure 309: Onshore Drillers JPMe Net Debt-to-EBITDA



Source: Company reports and J.P. Morgan estimates.

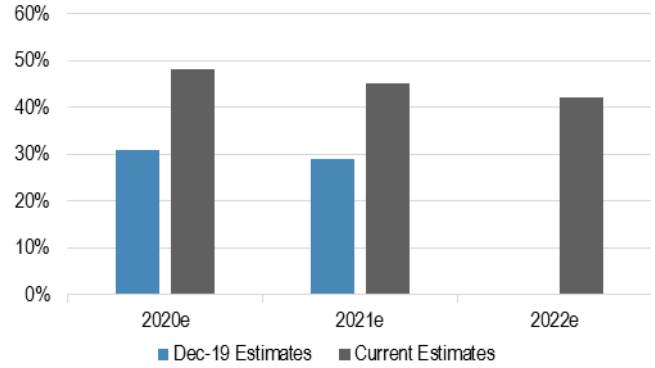
Figure 310: Offshore Drilling JPMe Net Debt-to-EBITDA



Source: Company reports and J.P. Morgan estimates.

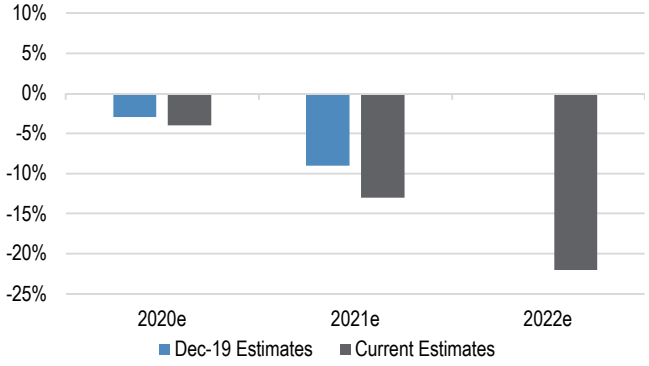
Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Figure 311: Diversifieds JPMe Net Debt-to-Capital



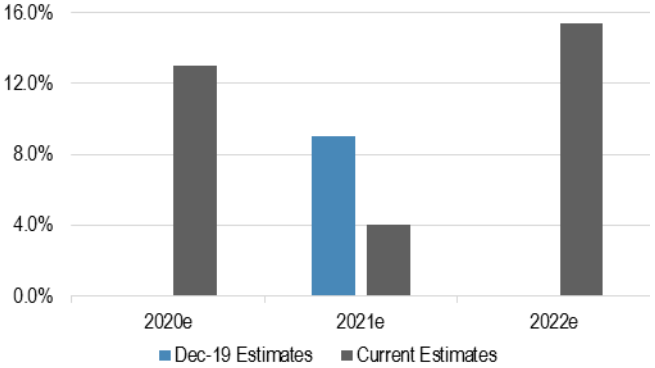
Source: Company reports and J.P. Morgan estimates.

Figure 312: Capital Equipment JPMe Net Debt-to-Capital



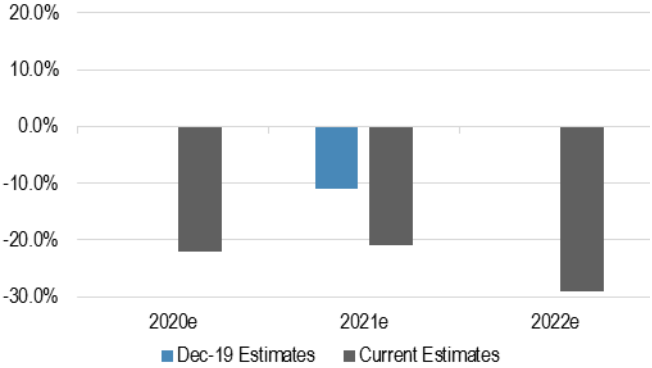
Source: Company reports and J.P. Morgan estimates.

Figure 313: Smid-Cap JPMe Net Debt-to-Capital



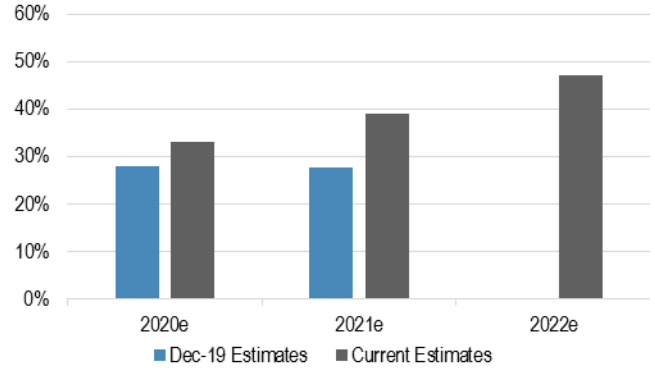
Source: Company reports and J.P. Morgan estimates.

Figure 314: Energy Distribution JPMe Net Debt-to-Capital



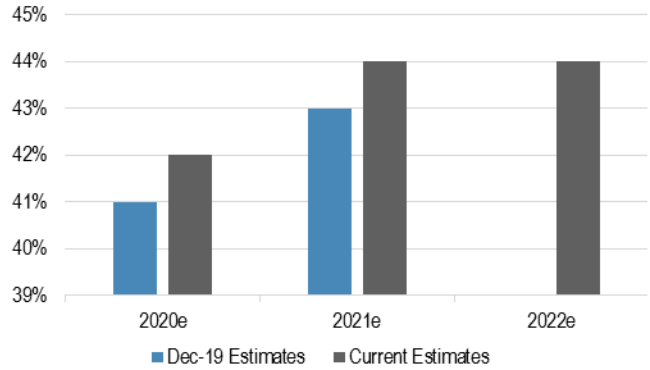
Source: Company reports and J.P. Morgan estimates.

Figure 315: Onshore Drillers JPMe Net Debt-to-Capital



Source: Company reports and J.P. Morgan estimates.

Figure 316: Offshore Drilling JPMe Net Debt-to-Capital

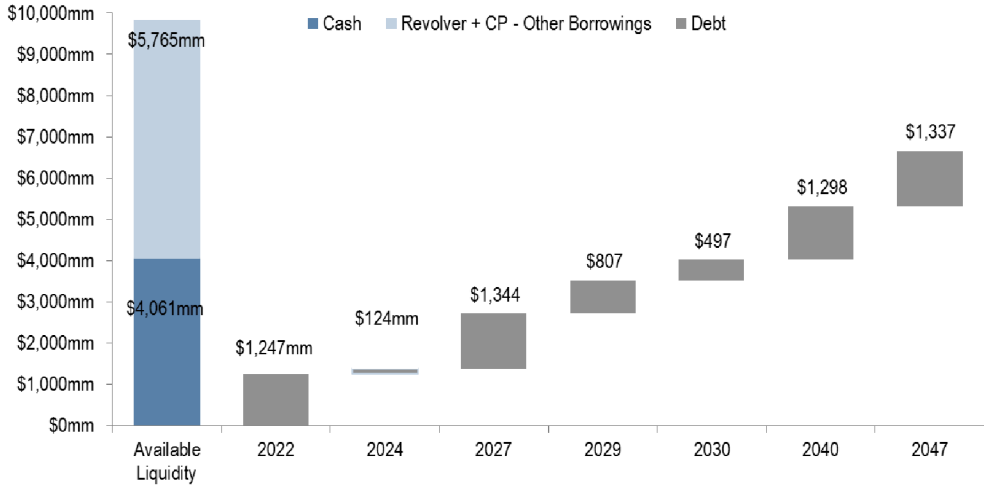


Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Baker Hughes (BKR)

Figure 317: Liquidity and Debt Waterfall



Source: Company reports.

Figure 318: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$1,247mm			12/1/2022	2.773%
	$1,344mm			12/1/2027	3.337%
	$522mm			11/1/2029	3.138%
	$497mm			5/1/2030	4.486%
	$1,337mm			12/1/2047	4.08%
Secured (Notes, Mortgages, etc)					
Unsecured	$124mm			6/1/2024	8.550%
	$285mm			1/1/2029	6.875%
	$1,298mm			9/1/2040	5.125%
Revolver / Credit Facility	$0mm	$3,000mm		12/1/2024	
Commercial Paper	$772mm	$3,800mm			
Other Borrowings	$263mm				

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Key Metrics

Total debt outstanding, gross	$7,689mm
Cash	$4,061mm
Total Liquidity Available	$10,089mm

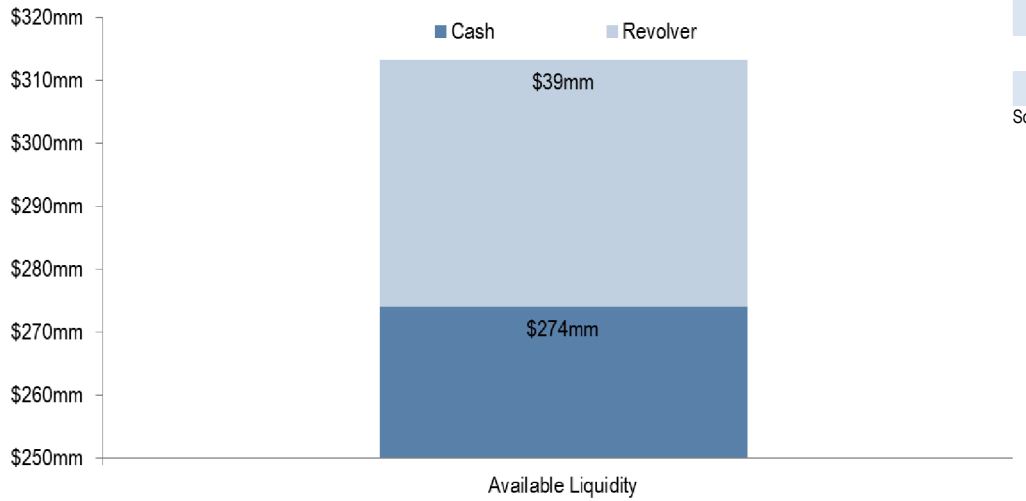
Source: Company reports and J.P. Morgan Estimates.

BKR does not currently have debt covenants.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Cactus Wellhead (WHD)

Figure 319: Liquidity and Debt Waterfall



Source: Company reports. Note: Capital structure for standalone TTI.

Key Metrics

Total debt outstanding, gross	$0mm
Cash	$274mm
Total Liquidity Available	$313mm

Source: Company reports and J.P. Morgan Estimates. Note: Includes CCLP.

Figure 320: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$75mm	$0mm	8/21/2023	ABR + .50%-1.00% Eurodollar+ 1.50%-2.00%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

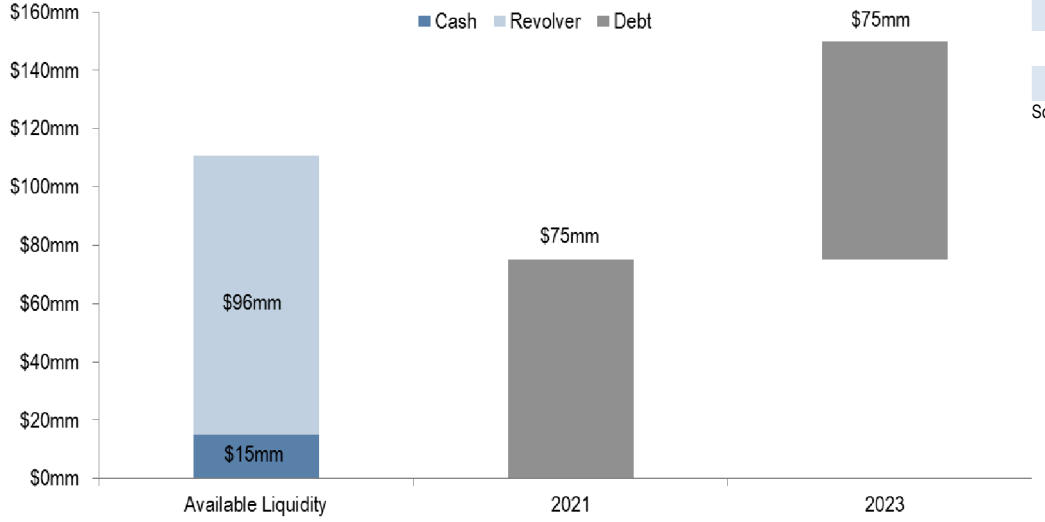
Fixed Charge Coverage Ratio
1.0:1.0

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Core Laboratories (CLB)

Figure 321: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$266mm
Cash	$15mm
Total Liquidity Available	$111mm

Source: Company reports and J.P. Morgan estimates.

Figure 322: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$75mm			9/30/2021	4.01%
	$75mm			9/30/2023	4.11%
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$116mm	$225mm	$13mm	6/19/2023	LIBOR + 1.5 - 2.875% (including a LIBOR floor of 0.5%)

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

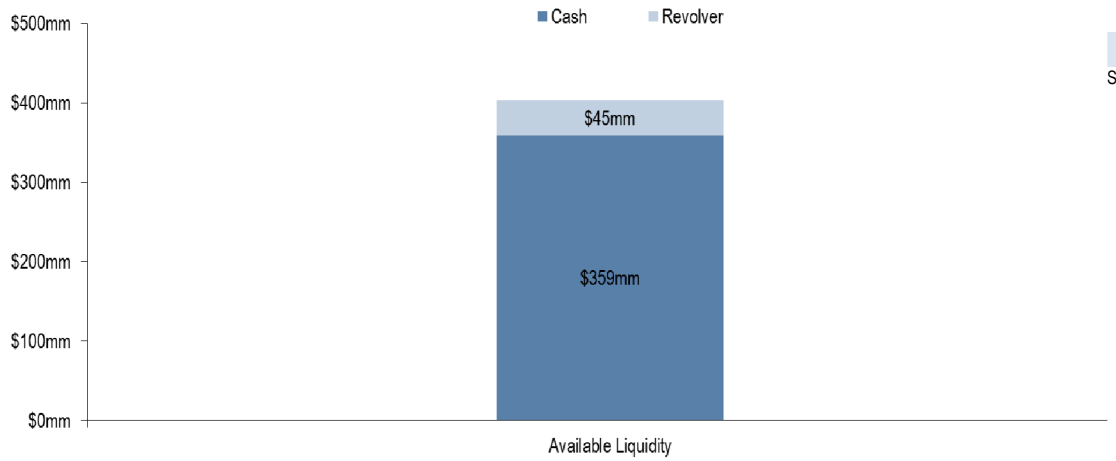
Interest Coverage Ratio (EBITDA / Interest):
≥3.0
Maximum Leverage Ratio (Max Consolidated Debt / EBITDA):
≤2.5

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Dril-Quip (DRQ)

Figure 323: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$56mm
Cash	$359mm
Total Liquidity Available	$404mm

Source: Company reports and J.P. Morgan Estimates.

Figure 324: Capital Structure Summary Table

Revolver / Credit Facility	$55mm	$100mm	$1mm	2/23/2023	LIBOR + 1.00% - 1.50%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

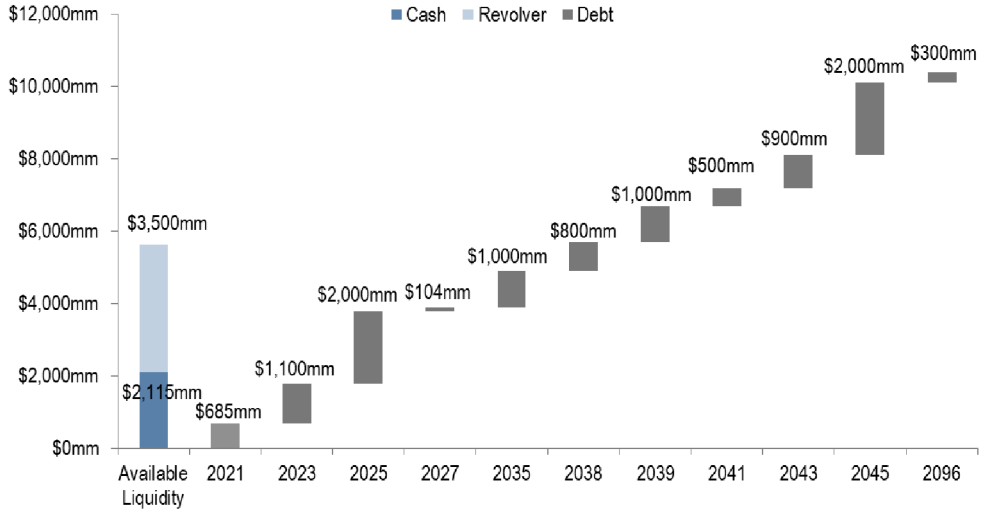
Covenants

FCCR
Maintain fixed coverage ratio of at least 1.1:1.0 when availability falls below the greater of $15mm or 20% of the lesser of the borrowing base or aggregate commitments

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Halliburton (HAL)

Figure 325: Liquidity and Debt Waterfall



Source: Company reports.

Figure 326: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$185mm			2/1/2021	8.75%
	$500mm			11/1/2021	3.25%
	$1,100mm			8/1/2023	3.50%
	$2,000mm			11/1/2025	3.80%
	$1,000mm			11/1/2035	4.85%
	$800mm			9/1/2038	6.70%
	$1,000mm			9/1/2039	7.45%
	$500mm			11/1/2041	4.50%
	$900mm			8/1/2043	4.75%
	$2,000mm			11/1/2045	5.00%
	$300mm			8/1/2096	7.60%
Secured (Notes, Mortgages, etc)					
Unsecured	$104mm			2/1/2027	6.75%
Revolver / Credit Facility	$0mm	$3,500mm		3/1/2024	

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Key Metrics

Total debt outstanding, gross	$10,389mm
Cash	$2,115mm
Total Liquidity Available	$5,615mm

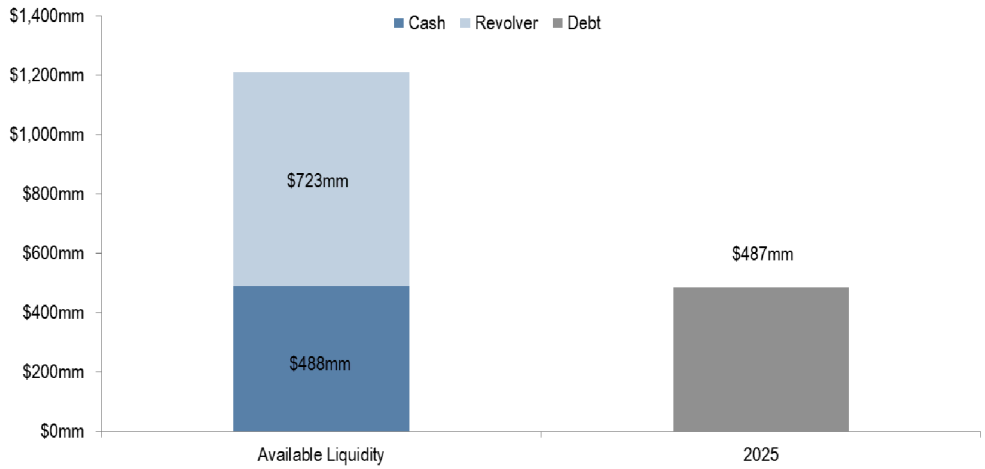
Source: Company reports and J.P. Morgan Estimates.

HAL does not currently have debt covenants.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Helmerich & Payne (HP)

Figure 327: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$528mm
Cash	$488mm
Total Liquidity Available	$1,217mm

Source: Company reports and J.P. Morgan Estimates.

Figure 328: Capital Structure Summary Table

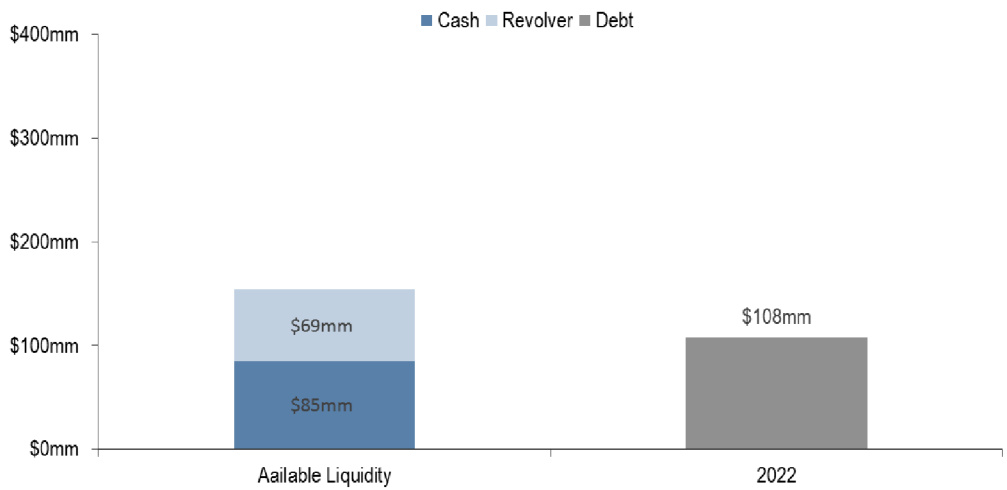
Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$487mm			3/19/2025	4.650%
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$750mm	$27mm	11/13/2024	LIBOR + 0.875 -1.50%
Unsecured standalone line of credit facility	$14mm	$20mm			

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Liberty Oilfield Services (LBRT)

Figure 329: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$109mm
Cash	$85mm
Total Liquidity Available	$154mm

Source: Company reports and J.P. Morgan Estimates.

Figure 330: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc	$108mm			9/19/2022	8.6%
Unsecured					
Revolver / Credit Facility	$0mm	$250mm	$0.8mm	9/19/2022	LIBOR or a base rate + LIBOR of 1.5% to 2.0% or base rate margin of 0.5% to 1.0%

Source: Company reports and J.P. Morgan estimates. Data as of 3Q20.

Covenants

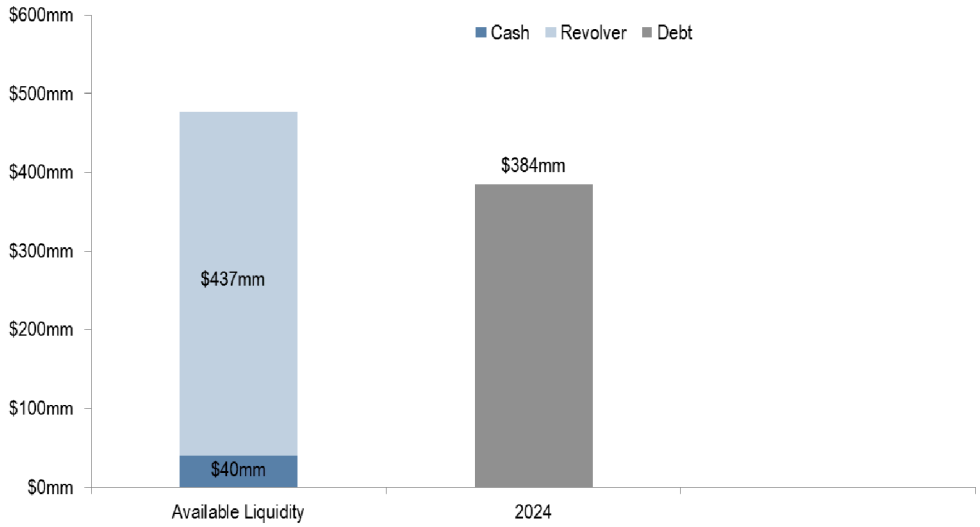
FCCR:
1.0:1.0 (for each period if excess availability is less than 10% of borrowing base or $12.5mm whichever is greater

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

MRC Global (MRC)

Figure 331: Liquidity and Debt Waterfall



Source: Company reports.

Figure 332: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured	$384mm			9/1/2024	4.92%
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$25mm	$462mm		9/1/2022	2.71%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Key Metrics

Total debt outstanding, gross	$409mm
Cash	$40mm
Total Liquidity Available	$477mm

Source: Company reports and J.P. Morgan Estimates.

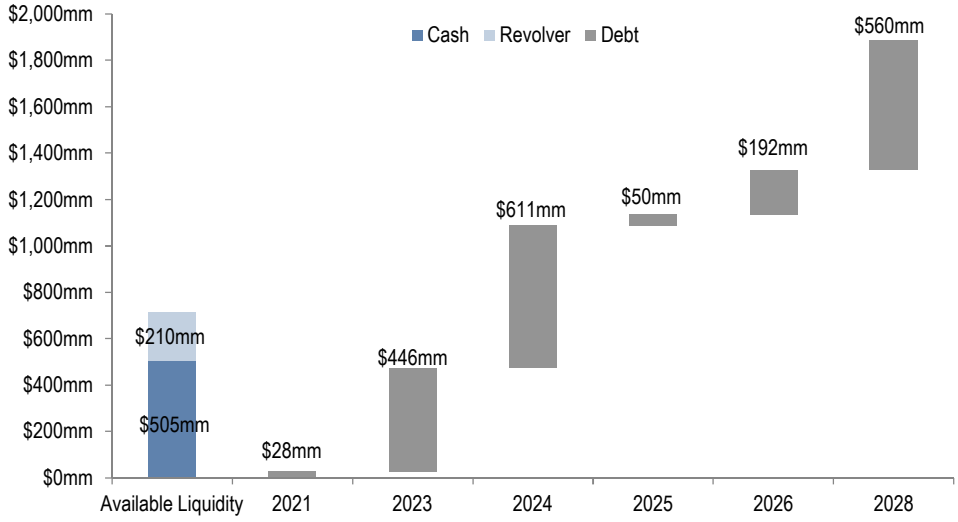
Covenants

Leverage Ratio Total:
≤5.0x
Junior Secured Leverage Ratio:
≤ 4.0x
Senior Secured Leverage Ratio:
< 4x

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Nabors Industries (NBR)

Figure 333: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$3,118mm
Cash	$505mm
Total Liquidity Available	$715mm

Source: Company reports and J.P. Morgan Estimates.

Figure 334: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$90mm			9/1/2021	4.625%
	$28mm			1/1/2023	5.50%
	$121mm			9/1/2023	5.10%
	$325mm			1/1/2024	0.75%
	$611mm			2/1/2025	5.75%
	$50mm			2/1/2025	6.50%
	$192mm			2/1/2025	9.00%
Secured (Notes, Mortgages, etc)	$560mm			1/1/2026	7.25%
	$390mm			1/1/2028	7.50%
Unsecured					
Revolver / Credit Facility	$752mm	$1,013mm	$27mm	10/11/2023	3.48%

Source: Company reports and J.P. Morgan estimates. Note: Debt data as of December 11, 2020, all others as of 3Q20.

Covenants

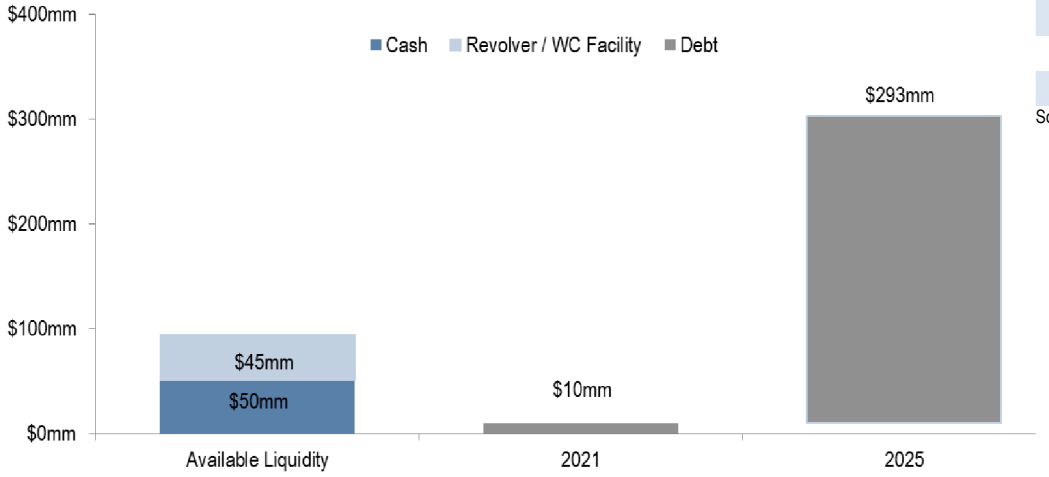
Net Debt to Capital
< 5.5x of EBITDA w/ Minimum Liquidity of $160mm
Leverage Ratio
< 2.50x
Debt Service Coverage
>2.50x

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

National Energy Services (NESR)

Figure 335: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$368mm
Cash	$50mm
Total Liquidity Available	$95mm

Source: Company reports and J.P. Morgan Estimates.

Figure 336: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)	$10mm			8/15/2021	2.25%
	$293mm			1/1/2025	3 mo. LIBOR + 2.4 -2.7%
Unsecured					
Revolver / Credit Facility	$65mm	$65mm		5/6/2023	3 mo. LIBOR +2.4 - 2.7% + Quarterly commitment fee of 0.6%
Working Capital Facility		$176mm	$131mm	365 Days	3 mo. US Dollar LIBOR + a margin of 1 - 1.25% per annum

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

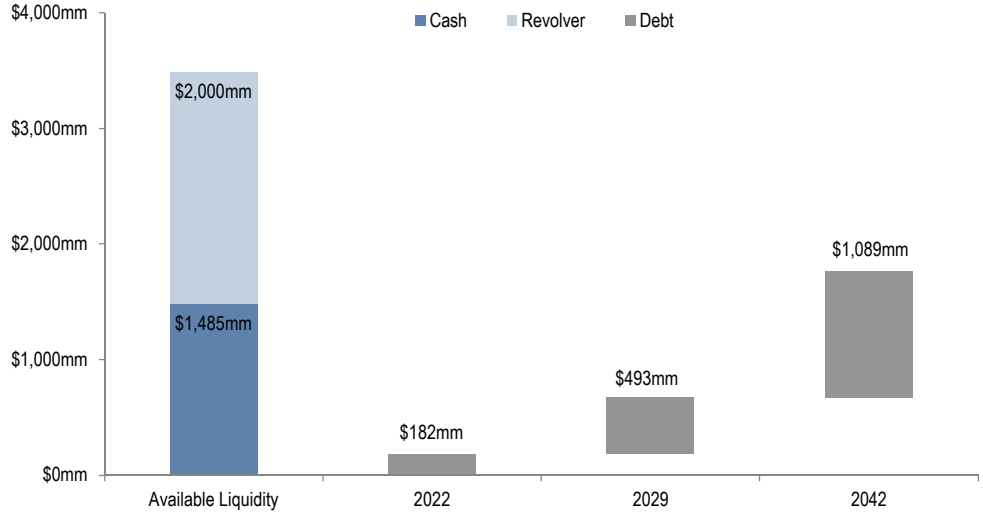
Covenants

Leverage Ratio (Net Debt/ EBITDA) :
< 3.50x
Minimum Debt Service Coverage Ratio:
1.25x
Minimum Interest Coverage Ratio:
4x

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

National Oilwell Varco (NOV)

Figure 337: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$1,824mm
Cash	$1,485mm
Total Liquidity Available	$3,485mm

Source: Company reports and J.P. Morgan Estimates.

Figure 338: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$182mm			12/1/2022	2.60%
	$493mm			12/1/2029	3.60%
	$1,089mm			12/1/2042	3.95%
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$2,000mm	$0mm	10/30/2024	LIBOR/NIBOR/ CDOR + 1.125%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

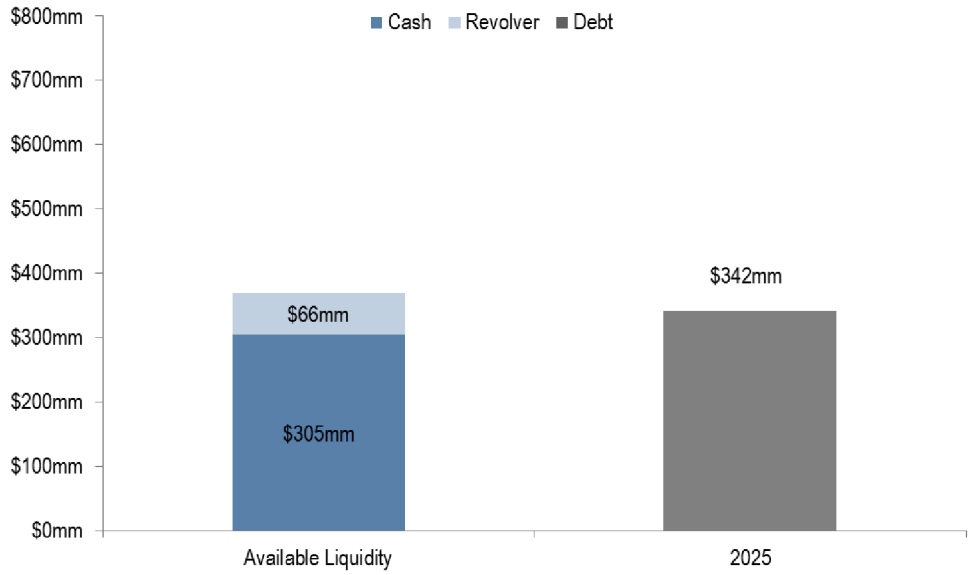
Leverage Ratio (Maximum Debt / Capitalization):
60%

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

NexTier Oilfield Solutions (NEX)

Figure 339: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$371m
Cash	$305mm
Total Liquidity Available	$371mm

Source: Company reports and J.P. Morgan Estimates.

Covenants

Fixed Charge Coverage Ratio:
1:1

Source: Company reports and J.P. Morgan estimates.

Figure 340: Capital Structure Summary Table

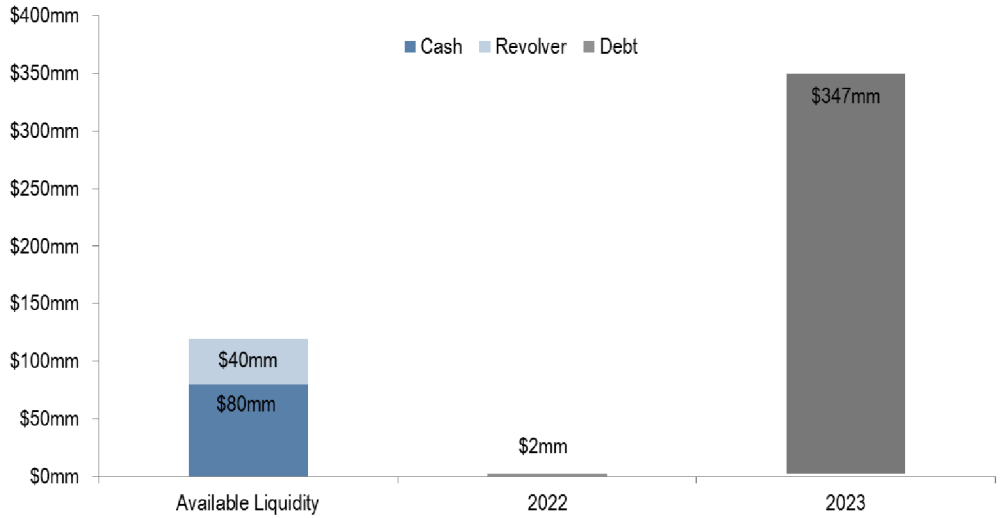
Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured	$342mm			5/25/2025	LIBOR + 3.5%
Revolver / Credit Facility	$0mm	$450mm	$29mm	10/31/2024	LIBOR or Base Rate + Applicable Margin

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Nine Energy Service (NINE)

Figure 341: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$350mm
Cash	$80mm
Total Liquidity Available	$120mm

Source: Company reports and J.P. Morgan Estimates.

Figure 342: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$347mm			11/1/2023	8.75%
Secured (Notes, Mortgages, etc)	$2mm			10/1/2022	6.00%
Unsecured					
Revolver / Credit Facility	$0mm	$200mm	$0.4mm	10/25/2023	Base Rate + 0.75%-1.25% LIBOR or CDOR +1.75- 2.25% Weighted Average Interest ~2.63%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20. NINE has less than the fully $200mm available under its ABL facility.

Covenants

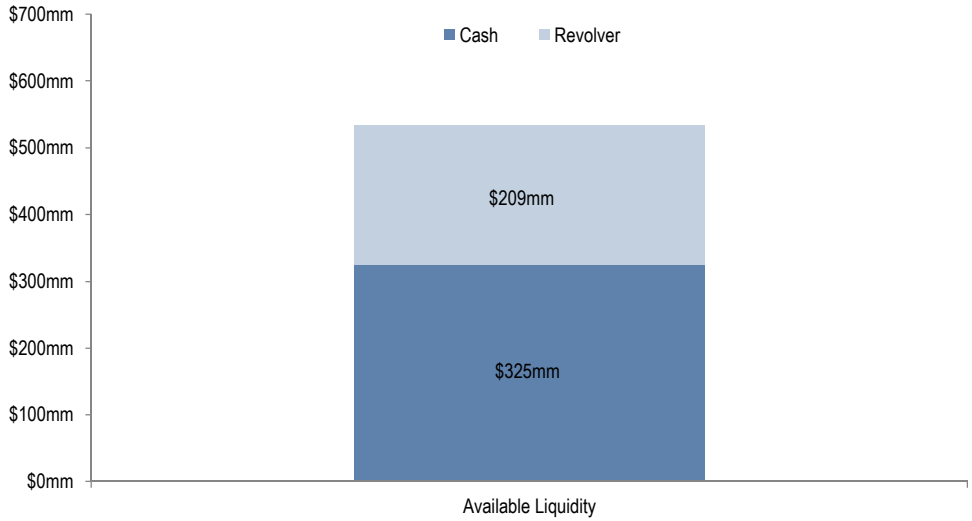
Leverage Ratio:
<2.5x
Fixed Charge Coverage Ratio:
1:1

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

NOW Inc. (DNOW)

Figure 343: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$7mm
Cash	$325mm
Total Liquidity Available	$534mm

Source: Company reports and J.P. Morgan Estimates.

Figure 344: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$750mm	$7mm	4/30/2023	Company choice of: Base rate+ margin of fixed charge coverage ratio or LIBOR + margin based on company's fixed charge coverage ratio (Additionally, the addition of a commitment fee of 25 - 37.5bps for unused portions of commitments)

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

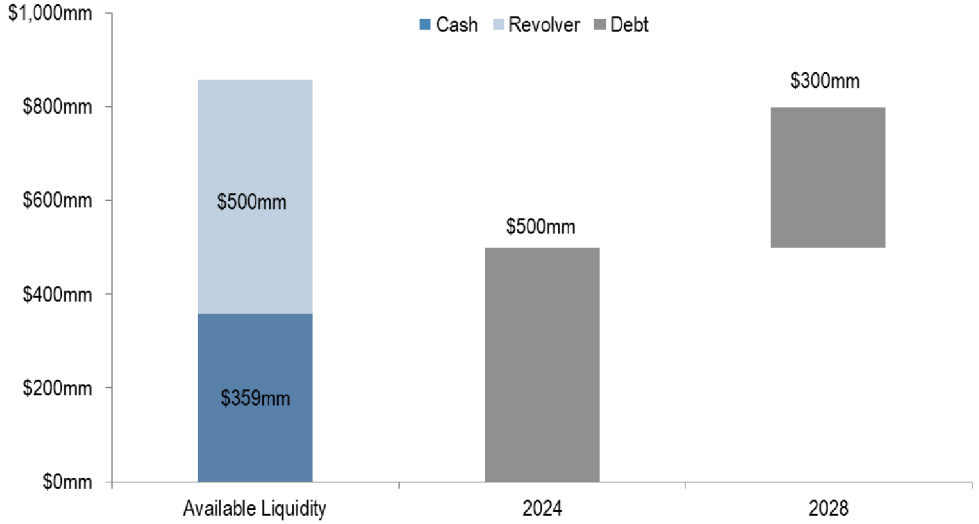
Fixed Charge Coverage Ratio:
Maintain a FCCR of at least 1:1 at the end of each fiscal quarter (if excess availability falls below 12.5% of the borrowing base or 60 million)

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Oceaneering International (OII)

Figure 345: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$806mm
Cash	$359mm
Total Liquidity Available	$859mm

Source: Company reports and J.P. Morgan Estimates.

Figure 346: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$500mm			11/15/2024	4.65%
	$300mm			2/1/2028	6.00%
	$12mm				
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$500mm	$0mm	1/25/2023	ABR + 0.125-0.750% / Euordollar + 1.125-1.750%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

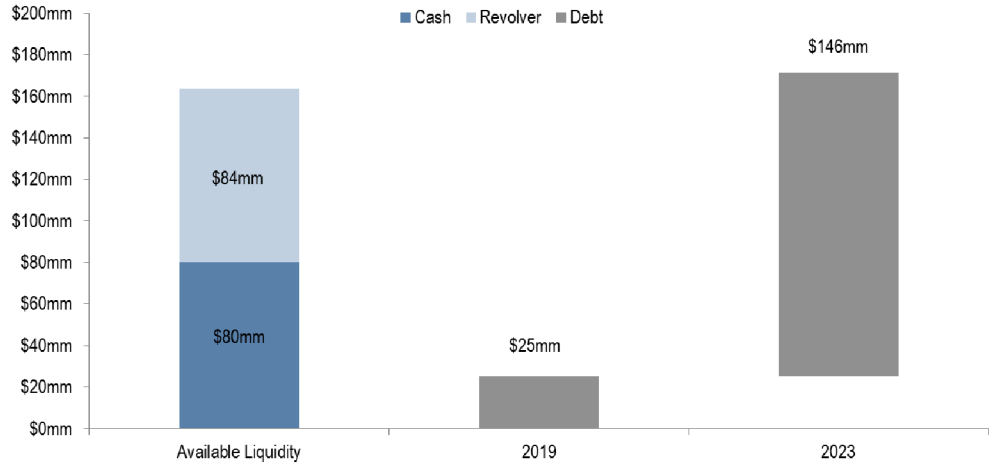
Leverage Ratio (Maximum Total Capitalization Ratio):
≤ 55%

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Oil States International (OIS)

Figure 347: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$189mm
Cash	$80mm
Total Liquidity Available	$164mm

Source: Company reports and J.P. Morgan Estimates. Note: Total debt includes capital lease obligations.

Figure 348: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)	$25mm			7/12/2019	2.50%
	$5mm			2/2/2023	
	$142mm			2/15/2023	1.50%
Unsecured					
Revolver / Credit Facility	$18mm	$200mm	$31mm	1/30/2022	LIBOR + 2.5-3.75% or Base rate + margin of 1.5-2.75% based on OIS's net funded debt to EBITDA. Additionally, OIS must pay a 0.5% fee based on undrawn credit.

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20; Convertible debt due 2023 is marked at a discount of face value of $157.4mm. Effective 1/1/21, the balance sheet will reflect the converts at their face value. See Note 2 in OIS's 10-Q for the accounting change.

Covenants

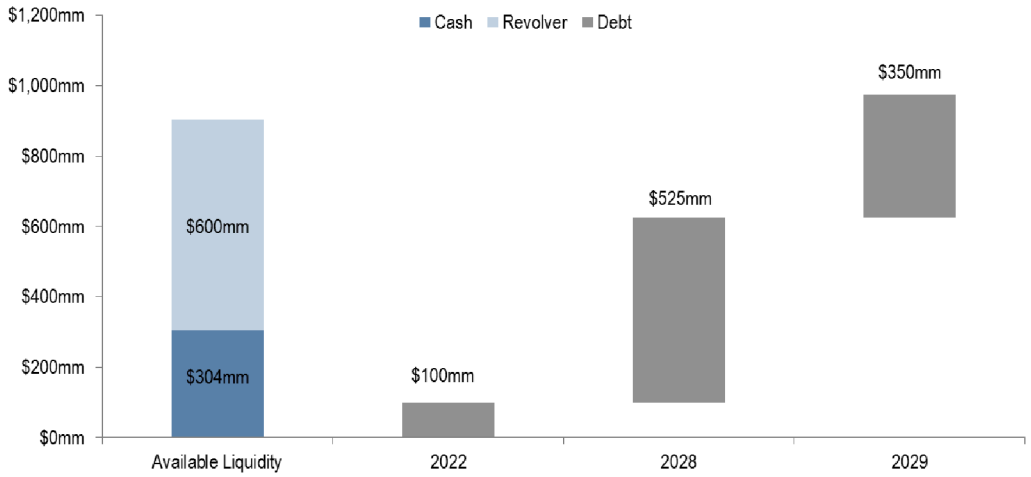
Interest Coverage Ratio (EBITDA / Interest):
3.00x – 1.00x
Maximum Leverage Ratio (Total Debt / EBITDA):
< 2.25x – 1.00x
Net Leverage Ratio
< 3.75x – 1.00x

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Patterson-UTI Energy (PTEN)

Figure 349: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$975mm
Cash	$304mm
Total Liquidity Available	$904mm

Source: Company reports and J.P. Morgan Estimates.

Figure 350: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$100mm			6/10/2022	1.52%
	$525mm			2/1/2028	3.95%
	$350mm			11/15/2029	5.15%
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$600mm	$0.1mm	3/27/2024	LIBOR + 1% - 2% Base Rate+ 0% - 1%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

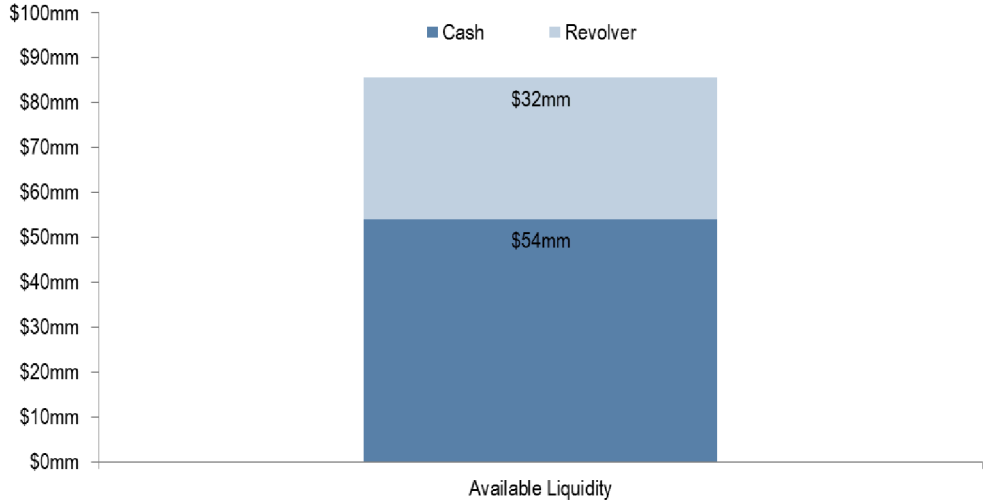
Interest Coverage Ratio (EBITDA / Interest):
≥2.5x (Senior Unsecured Debt)
Leverage Ratio (Debt / Capitalization):
≤50%

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

ProPetro Holding (PUMP)

Figure 351: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$0mm
Cash	$54mm
Total Liquidity Available	$86mm

Source: Company reports and J.P. Morgan Estimates.

Figure 352: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$35mm	$4mm	12/19/2023	LIBOR + 1.75-2.25% or Base Rate + 0.75-1.25%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

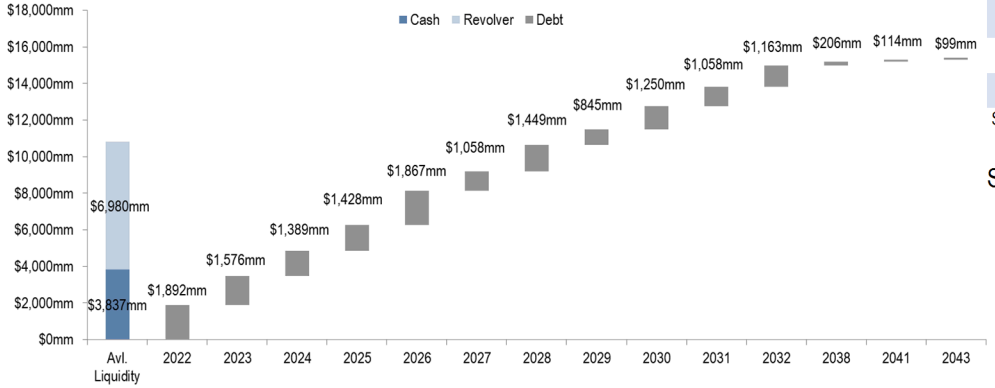
Fixed Charge Coverage Ratio:
1.0x

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Schlumberger (SLB)

Figure 353: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$16,471mm
Cash	$3,837mm
Total Liquidity Available	$10,817mm

Source: Company reports and J.P. Morgan Estimates.

SLB does not currently have debt covenants.

Figure 354: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$999mm			2022	2.40%
	$598mm			2022	2.65%
	$295mm			2022	3.63%
	$1,496mm			2023	3.65%
	$746mm			2024	3.75%
	$498mm			2025	1.40%
	$930mm			2025	4.00%
	$1,163mm			2026	1.38%
	$1,449mm			2028	3.90%
	$845mm			2029	4.30%
	$1,250mm			2030	2.65%
	$1,163mm			2032	2.00%
Secured (Notes, Mortgages, etc)					
Unsecured	$80mm			2023	4.00%
	$588mm			2024	0.00%
	$55mm			2024	3.70%
	$704mm			2026	1.00%
	$1,058mm			2027	0.25%
	$1,058mm			2031	0.50%
	$206mm			2038	7.00%
	$114mm			2041	5.95%
	$99mm			2043	5.13%
Revolver / Credit Facility	$0mm	$8,060mm	$1,077mm	9/1/2021	

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Select Energy Services (WTTR)

Figure 355: Liquidity and Debt Waterfall

Source: Company reports.

Key Metrics

Total debt outstanding, gross	$0mm
Cash	$185mm
Total Liquidity Available	$233mm

Source: Company reports and J.P. Morgan Estimates

Figure 356: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured					
Revolver / Credit Facility	$0mm	$300mm	$16mm	11/1/2022	LIBOR + 1.5-2.0% Base Rate 0.50 -1.00%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

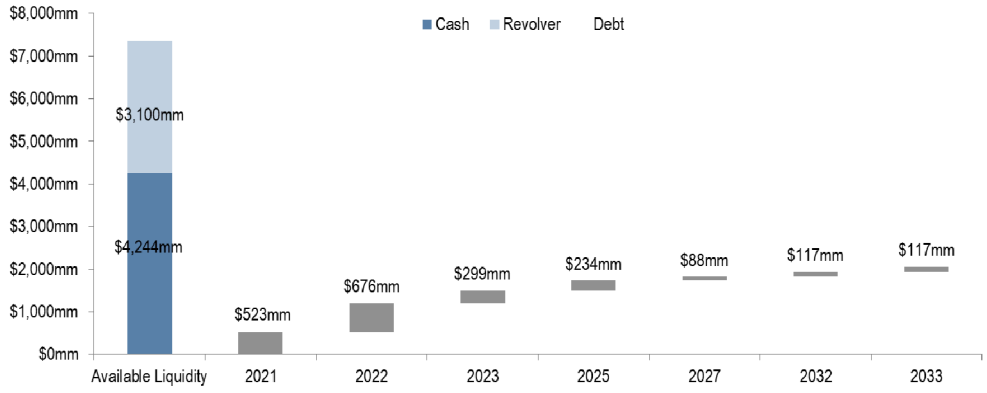
Fixed Charge Coverage Ratio:
>1.0

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

TechnipFMC (FTI)

Figure 357: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross*	$2,753mm
Cash	$4,244mm
Total Liquidity Available*	$6,544mm

Source: Company reports and J.P. Morgan estimates.

Figure 358: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured	$500mm			2022	3.45%
Secured (Notes, Mortgages, etc)					
Unsecured	$523mm			2021	
	$176mm			2022	3.40%
	$152mm			2023	3.15%
	$146mm			2023	3.15%
	$234mm			2025	4.50%
	$88mm			2027	4.00%
	$117mm			2032	4.00%
	$117mm			2033	3.75%
Revolver / Credit Facility	$0mm	$3,900mm	$800mm	Varies	Currency Varies the Interest Rate
Commercial Paper	$700mm	$1,500mm			

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Covenants

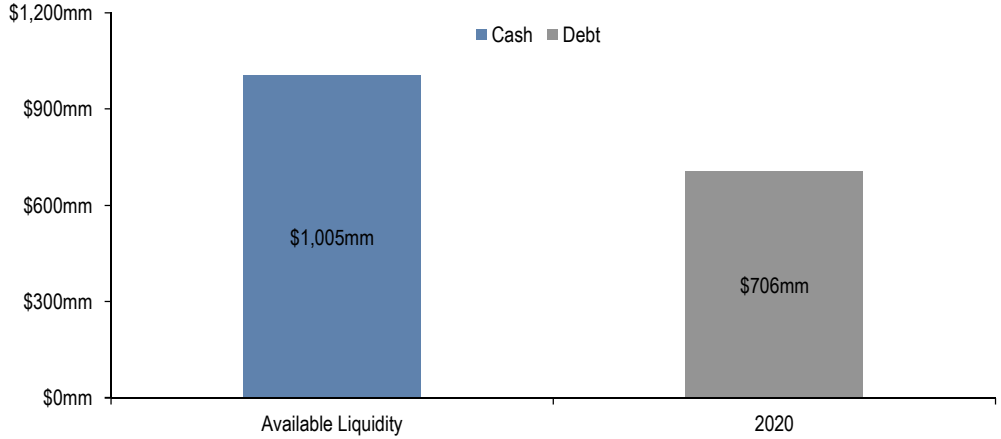
Total Capitalization Ratio:
<60% in any given quarter

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Tenaris (TS)

Figure 359: Liquidity and Debt Waterfall



Source: Company reports.

Key Metrics

Total debt outstanding, gross	$706mm
Cash	$1,005mm
Total Liquidity Available	$1,005mm

Source: Company reports and J.P. Morgan Estimates.

Figure 360: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured					
Senior Unsecured					
Secured (Notes, Mortgages, etc)					
Unsecured*	$706mm				
Revolver / Credit Facility					

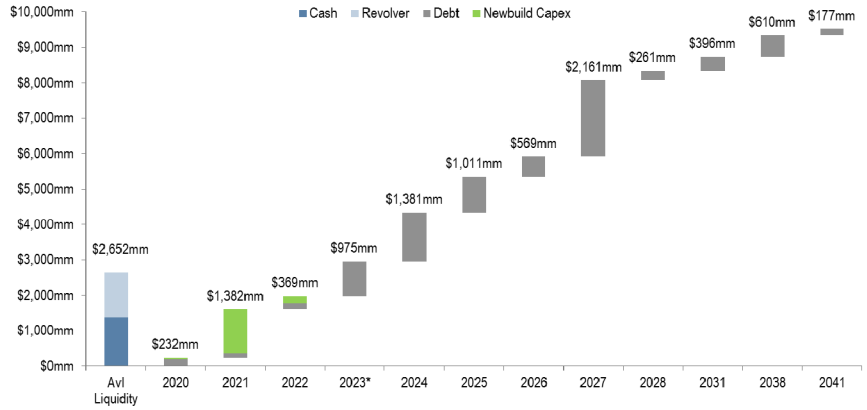
Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

*TS debt consists of short term bank loans primarily used for hedging foreign currency exposure

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Transocean (RIG)

Figure 361: Liquidity and Debt Waterfall



*Revolver maturity: $1,300mm in 2023

Source: Company reports and J.P. Morgan Estimates.

Figure 362: Capital Structure Summary Table

Long-term Debt, gross	Outstanding	Commitment	Letters of Credit Outstanding	Maturity	Interest Rate
Senior Secured	$134mm			May-22	5.52%
	$504mm			May-23	5.375%
	$585mm			Jan-24	5.875%
	$390mm			Oct-24	7.75%
	$406mm			Dec-24	6.25%
	$468mm			Aug-25	6.125%
	$687mm			Jan-27	11.50%
	$238mm			Jan-27	2.50%
	$550mm			Feb-27	6.875%
Senior Unsecured	$191mm			Nov-20	6.50%
	$116mm			Dec-21	6.375%
	$37mm			Oct-22	3.80%
	$463mm			Jan-23	0.50%
	$543mm			Nov-25	7.25%
	$569mm			Jan-26	7.50%
	$612mm			Feb-27	8.00%
	$610mm			Mar-38	6.80%
	$177mm			Dec-41	7.35%
Secured (Notes, Mortgages, etc)	$52mm			Apr-27	7.45%
	$261mm			Jun-28	7.00%
	$396mm			Apr-31	7.50%
Unsecured	$22mm			Apr-27	8.00%
Newbuild Capex	$722mm			2021-2022	
	$750mm			2021-2022	
Revolver / Credit Facility	$0mm	$1,300mm	$30mm	6/23/2023	LIBOR + 2.625-3.375%

Source: Company reports and J.P. Morgan estimates. Note: Data as of 3Q20.

Key Metrics

Total debt outstanding, gross*	$8,011mm
Cash*	$1,382mm
Total Liquidity Available	$2,652mm

Source: Company reports and J.P. Morgan Estimates

Covenants

Leverage Ratio (Max Debt / Tangible Capitalization):
60%

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Company Outlooks

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Baker Hughes (BKR)

The Year Ahead for BKR

After a year of disruption, we think Baker Hughes will continue to differentiate v. peers in 2021 with its advantaged backlog, balance sheet and end markets (including strong new energy positioning). The pace of GE equity sales hampered the stock midyear but BKR has been able to snap back powerfully since. While this dynamic may put pressure on the shares at times, we continue to believe BKR will show an increasingly clear path to higher earnings cycle over cycle (a rarity in our coverage). Top line and margin expectations for TPS remain low in our view and we side with BKR on LNG's longer term prospects (i.e. 650-700mtpa by 2030, meaning another 50-100mtpa in orders over the next ~3 years). BKR's proven progress in regaining its OFS foothold internationally was only temporarily put on hold during this volatile year and OFS margins are set to trend higher in our view. Baker shares have outperformed among the diversifieds, and the broader OFS sector through 2020 (-14% YTD v. -41% OSX) given the company's longer and later-cycle exposures, which we expect to continue to benefit BKR as the "oil beta" recovery underwhelms.

Things to Focus On in 2021

- **TPS has the ability to impress, OFS and OFE relatively restrained.** We think investors have been overly skeptical of TPS's trajectory over the next few years given LNG's critical role in the evolving energy mix. BKR sees 3-4 more FIDs in 2021 which could equate to ~$1bn of equipment inbound, similar to the Qatar NFE award received in 2020, layering onto a stable +$5bn order floor. From there, margins will benefit from higher services mix into 2022. In OFS Baker will look to further recapture market share on a tepidly improving macro in 2021 but OFE will remain constrained on considerably weaker orders. Both segments exhibited strong cost-out execution in 3Q, making 2021's prospects better (from a low base).
- **Catching the energy transition tailwind.** We think BKR's position in the energy transition can prove to be significant in the long-term (especially compared to OFS as a whole). The LNG leader has the ability to pivot with the market on hydrogen and carbon capture while benefitting from the trend of lowering emissions in the more near term (e.g. LNG, equipment high-grading, Digital Solutions). We think continued transparency in 2021 will help investors gain further confidence in BKR's differentiated story.
- **Free cash flow potential in focus with GE overhang lingering.** While we model restructuring-hamstrung 2020 FCF at ~$330mm (only ~2% yield), we expect a solid $1.1bn of free cash in 2021 (~6% yield), lapping ~$800mm in cash costs. BKR is indicating there will be considerably less of a cash drag, but it still won't be zero. GE has reduced its equity stake in Baker Hughes to ~34% from the initial ~63% level. At the current pace (and assuming similar average volume), we think the position can be unwound by 1H23 (or sooner if BKR and GE agree to accelerate). Strong FCF could open the door to a resumption of share repurchases.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 20: Baker Hughes Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Turbomachinery and Process Solutions			$6,295	$6,016	$5,536	$1,085	$1,161	$1,513	$1,940	$5,699	$1,376	$1,438	$1,564	$1,876	$6,254	$6,523
Oilfield Services			$10,361	$11,617	$12,889	$3,139	$2,411	$2,308	$2,181	$10,038	$2,237	$2,379	$2,475	$2,427	$9,517	$10,113
Oilfield Equipment			$2,660	$2,641	$2,921	$712	$696	$726	$736	$2,870	$676	$650	$624	$650	$2,600	$2,694
Digital Solutions			$2,524	$2,604	$2,492	$489	$468	$503	$540	$2,000	$503	$513	$524	$545	$2,084	$2,207
Total Revenue	**$15,742**	**$9,841**	**$21,840**	**$22,878**	**$23,838**	**$5,425**	**$4,736**	**$5,049**	**$5,397**	**$20,607**	**$4,791**	**$4,981**	**$5,186**	**$5,498**	**$20,456**	**$21,537**
Total D&A	($1,742)	($1,166)	($1,629)	($1,486)	($1,419)	($355)	($340)	($315)	($315)	($1,325)	($312)	($309)	($306)	($303)	($1,229)	($1,180)
EBITDA	**$1,815**	**$493**	**$2,486**	**$2,878**	**$3,022**	**$595**	**$444**	**$549**	**$672**	**$2,260**	**$529**	**$552**	**$608**	**$710**	**$2,399**	**$2,770**
EBITDA Margins	11.5%	5.0%	11.4%	12.6%	12.7%	11.0%	9.4%	10.9%	12.5%	11.0%	11.0%	11.1%	11.7%	12.9%	11.7%	12.9%
Turbomachinery and Process Solutions			$665	$621	$719	$134	$149	$191	$298	$772	$158	$174	$211	$305	$848	$1,033
Oilfield Services			$292	$785	$918	$206	$46	$93	$89	$434	$98	$112	$131	$122	$462	$587
Oilfield Equipment			$25	$0	$56	($8)	($14)	$19	$29	$26	$20	$12	$4	$12	$47	$75
Digital Solutions			$320	$390	$343	$29	$41	$46	$53	$169	$52	$56	$60	$68	$236	$286
Total Operating Income	**$73**	**($673)**	**$857**	**$1,392**	**$1,603**	**$240**	**$104**	**$234**	**$357**	**$935**	**$217**	**$244**	**$302**	**$408**	**$1,170**	**$1,590**
Total Operating Margins	0.5%	-6.8%	3.9%	6.1%	6.7%	4.4%	2.2%	4.6%	6.6%	4.5%	4.5%	4.9%	5.8%	7.4%	5.7%	7.4%
Income Taxes	($72)	$72	($275)	($466)	($507)	($89)	$177	$30	($102)	$16	($56)	($65)	($85)	($121)	($327)	($466)
Tax Rate	*-50%*	*8%*	*47%*	*44%*	*36%*	*43%*	*81%*	*-158%*	*35%*	*-2%*	*35%*	*35%*	*35%*	*35%*	*35%*	*35%*
Net Income	**($1,967)**	**($2,737)**	**$166**	**$277**	**$473**	**$70**	**($31)**	**$27**	**$118**	**$184**	**$64**	**$74**	**$96**	**$137**	**$370**	**$537**
Diluted Shares (Avg)	438	437	1,152	435	567	653	655	676	676	671	671	671	671	671	671	671
EPS (Adjusted, Diluted)	**($0.48)**	**($1.79)**	**$0.14**	**$0.64**	**$0.83**	**$0.11**	**($0.05)**	**$0.04**	**$0.17**	**$0.27**	**$0.10**	**$0.11**	**$0.14**	**$0.20**	**$0.55**	**$0.80**
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	1,245	1,114	(1,899)	274	437	345	(6)	(133)	(2)	204	(8)	(85)	82	(60)	(71)	(125)
Cash from Operations	**$1,796**	**$4,229**	**($84)**	**$1,762**	**$2,126**	**$478**	**$230**	**$219**	**$173**	**$1,100**	**$388**	**$293**	**$518**	**$438**	**$1,637**	**$1,876**
Capital Expenditures	($965)	($332)	($849)	($995)	($976)	($325)	($167)	($167)	($113)	($772)	($129)	($134)	($140)	($148)	($552)	($603)
Cash from Investing	**($905)**	**$203**	**($910)**	**($578)**	**($1,045)**	**($318)**	**($119)**	**($114)**	**($60)**	**($611)**	**($129)**	**($134)**	**($140)**	**($148)**	**($552)**	**($603)**
Increase (decrease) in Debt	($45)	($1,195)	$3,444	($684)	($587)	($115)	$1,203	($21)	$0	$1,067	$0	$0	$0	$0	$0	$0
Cash from Financing	**($282)**	**($2,185)**	**$2,214**	**($4,363)**	**($1,534)**	**($327)**	**$1,022**	**($201)**	**($193)**	**$301**	**($193)**	**($193)**	**($193)**	**($193)**	**($773)**	**($773)**
Cash at End of Period	**$2,324**	**$4,572**	**$7,023**	**$3,723**	**$3,249**	**$3,010**	**$4,132**	**$4,061**	**$3,980**	**$3,980**	**$4,045**	**$4,010**	**$4,195**	**$4,292**	**$4,292**	**$4,793**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (Net)	6,693	4,271	6,959	6,228	6,240	5,997	5,710	5,536	5,334	5,334	5,152	4,978	4,812	4,658	4,658	4,080
Total Assets	**$24,080**	**$19,034**	**$57,050**	**$52,439**	**$53,369**	**$37,229**	**$37,523**	**$37,339**	**$37,572**	**$37,572**	**$37,098**	**$36,945**	**$37,033**	**$37,305**	**$37,305**	**$37,404**
Long-term Debt, Net of Current	**3,890**	**2,886**	**6,312**	**6,285**	**6,301**	**6,285**	**6,766**	**6,754**	**6,754**	**6,754**	**6,754**	**6,754**	**6,754**	**6,754**	**6,754**	**6,754**
Stockholder Equity	16,382	12,737	39,173	35,013	34,499	17,985	17,565	17,249	16,969	16,969	16,859	16,735	16,672	16,675	16,675	16,723
Cash Flow Metrics																
Cash from Operations	$1,796	$4,229	($84)	$1,762	$2,126	$478	$230	$219	$173	$1,100	$388	$293	$518	$438	$1,637	$1,876
Capital Expenditures	($965)	($332)	($849)	($995)	($976)	($325)	($167)	($167)	($113)	($772)	($129)	($134)	($140)	($148)	($552)	($603)
Divestitures	$388	$283	$211	$458	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Cash Flow	**$831**	**$3,897**	**($933)**	**$900**	**$1,150**	**$153**	**$63**	**$52**	**$60**	**$328**	**$258**	**$158**	**$378**	**$290**	**$1,084**	**$1,273**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Cactus Wellhead (WHD)

The Year Ahead for WHD

Cactus has weathered the 2020 storm quite impressively in the face of the pandemic-associated collapse in NAM land activity, and its share performance has rightly outpaced the sector and peers (-18% YTD v. -41% OSX, -44% equipment peers). WHD's strong value proposition and limited competition helped it reach yet another level record of market share in 3Q20, underpinning its stability. While we expect the pace of gains to slow as improving activity allows more competitors to re-enter the market, the company has many avenues to enhance its positioning. Tariff reimbursements (not extended past August) have helped cushion margins, but well-executed cost-out and pricing discipline were evident nonetheless; the company's focus on maintaining margins over volume growth should help ease worries going forward. Although WHD has singular exposure to NAM completions, the company's disciplined management team and strategic positioning leave it as one of the best options for growth in the space. International expansion remains a key 2021 question.

Things to Focus On in 2021

- **Defining the path to further share gains.** WHD has continued to grow market share impressively (most recently to ~38% as of 3Q) by taking advantage of downturns to demonstrate its value proposition v. peers. While most gains to date have come from the majors and privates, WHD's efforts with large E&Ps have lagged; with better visibility going forward, 2021 presents an opportunity for significant progress on the Products side. Notably, the company has been on both sides of most E&P consolidations in 2020, opening the door to potential new business as best practices are adopted.
- **New rental technology should help offset pricing headwinds.** Throughout the downturn, WHD has maintained discipline and declined to do work at unsustainably low prices, negatively impacting Rental top line. Pricing deterioration presents a potential roadblock for new product penetration if customers are less willing to pay the higher price for it; however, an important part of the value proposition is that most of the company's offerings require little capital. In 1Q21, WHD plans to deploy enhanced remote capabilities in rental equipment. As activity improves incrementally, the company should achieve further customer adoption, softening the blow to pricing; we model Rental revenue declining only -7% y/y in 2021. E&P consolidation may also prove to be a tailwind for the segment, as Cactus's value proposition becomes more attractive for larger companies.
- **Addressing the return of capital to shareholders.** With ~$280mm in cash on hand as of 3Q and that amount expected to grow, WHD retains dry powder to use strategically. Sustaining the dividend at the healthy levels of cash flow it generates seems reasonable to us. Management has indicated share buybacks are not consistent with the company's capital allocation, leaving inorganic growth as the other alternative for excess cash. M&A remains a potential option, but an attractive opportunity with tangible synergies would have to materialize (and the options seem limited in the foreseeable future). We still see a purchase of an international footprint as the best use of inorganic capital for WHD, but timing and valuation of such deals are always tricky.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 21: Cactus Wellhead Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Product revenue	111	78	189	290	357	87	41	36	43	206	50	55	60	60	224	277
Rental revenue	65	44	77	133	142	36	12	10	10	67	13	15	17	17	62	68
Field Service and Other revenue	45	33	75	120	130	31	14	14	15	75	16	18	20	20	75	90
Total Revenue	**$221**	**$155**	**$341**	**$544**	**$628**	**$154**	**$67**	**$60**	**$68**	**$348**	**$79**	**$89**	**$96**	**$97**	**$361**	**$435**
COGS	(137)	(105)	(209)	(326)	(394)	(99)	(48)	(39)	(51)	(237)	(58)	(63)	(67)	(67)	(256)	(268)
SG&A	(21)	(19)	(27)	(41)	(52)	(14)	(9)	(8)	(9)	(40)	(11)	(12)	(13)	(13)	(49)	(59)
Total Costs & Expenses	**($158)**	**($123)**	**($235)**	**($367)**	**($445)**	**($113)**	**($57)**	**($47)**	**($59)**	**($276)**	**($69)**	**($76)**	**($80)**	**($79)**	**($304)**	**($327)**
Total D&A	($21)	($21)	($23)	($30)	($39)	($11)	($11)	($10)	($10)	($42)	($11)	($11)	($10)	($10)	($41)	($37)
Total Gross Profit	**$84**	**$50**	**$139**	**$248**	**$274**	**$66**	**$28**	**$30**	**$27**	**$151**	**$32**	**$36**	**$39**	**$39**	**$146**	**$202**
Total Gross Margins	38.1%	32.6%	40.7%	45.6%	43.5%	42.6%	42.7%	50.6%	40.1%	43.5%	39.8%	40.6%	40.7%	40.8%	40.5%	46.5%
EBITDA Companywide	**$63**	**$34**	**$112**	**$211**	**$229**	**$54**	**$22**	**$25**	**$21**	**$122**	**$23**	**$26**	**$29**	**$29**	**$107**	**$155**
Total EBITDA Margin	28.4%	22.0%	32.9%	38.8%	36.4%	35.0%	33.8%	41.1%	30.6%	34.9%	28.8%	29.1%	30.2%	29.8%	29.5%	35.5%
Interest Expense	(22)	(20)	(20)	(1)	0	0	0	0	0	0	0	0	0	0	0	0
Other Income (expense)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	($0)	($0)	($2)	($26)	($44)	($11)	($3)	($3)	($2)	($19)	($2)	($4)	($5)	($5)	($16)	($28)
Tax Rate	*1%*	*0%*	*3%*	*15%*	*24%*	*26%*	*26%*	*24%*	*26%*	*26%*	*26%*	*28%*	*28%*	*28%*	*28%*	*26%*
Net Income	**$21**	**($8)**	**$67**	**$150**	**$156**	**$33**	**$9**	**$15**	**$6**	**$63**	**$7**	**$9**	**$12**	**$12**	**$41**	**$79**
Diluted Shares (Avg)		53	53	75	75	75	75	76	76	76	76	76	76	76	76	76
EPS (Adjusted, Diluted)		**($0.15)**	**$1.24**	**$1.60**	**$1.86**	**$0.41**	**$0.10**	**$0.13**	**$0.08**	**$0.71**	**$0.09**	**$0.12**	**$0.16**	**$0.16**	**$0.54**	**$1.04**
Dividend per Share		$0.00	$0.00	$0.00	$0.09	$0.09	$0.09	$0.09	$0.09	$0.36	$0.09	$0.09	$0.09	$0.09	$0.36	$0.36
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	0	8	(59)	(40)	(16)	(9)	37	(5)	8	31	24	(2)	8	3	33	9
Cash from Operations	**$46**	**$24**	**$35**	**$167**	**$210**	**$45**	**$57**	**$19**	**$25**	**$150**	**$42**	**$18**	**$30**	**$25**	**$115**	**$125**
Capital Expenditures	($25)	($19)	($32)	($70)	($60)	($9)	($9)	($3)	($3)	($24)	($5)	($6)	($7)	($6)	($24)	($30)
Cash from Investing	**($23)**	**($15)**	**($31)**	**($68)**	**($56)**	**($8)**	**($8)**	**($3)**	**($3)**	**($23)**	**($5)**	**($6)**	**($7)**	**($6)**	**($24)**	**($30)**
Increase (decrease) in Debt	($11)	($8)	($5)	($249)	($7)	($2)	$0	$0	$0	($2)	$0	$0	$0	$0	$0	$0
Cash from Financing	**($23)**	**($13)**	**($5)**	**($35)**	**($22)**	**($10)**	**($8)**	**($7)**	**($7)**	**($30)**	**($7)**	**($7)**	**($7)**	**($7)**	**($27)**	**($27)**
Cash at End of Period	**$13**	**$9**	**$8**	**$71**	**$202**	**$230**	**$270**	**$280**	**$295**	**$295**	**$325**	**$331**	**$347**	**$359**	**$359**	**$427**
Balance Sheet ($ in millions)																
Total Assets	**$178**	**$165**	**$266**	**$585**	**$835**	**$850**	**$822**	**$811**	**$824**	**$824**	**$837**	**$846**	**$857**	**$863**	**$863**	**$929**
Long-term Debt, Net of Current	**251**	**242**	**241**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Stockholder Equity	(93)	(103)	(36)	362	516	542	548	547	546	546	546	549	554	559	559	611
Cash Flow Metrics																
Free Cash Flow		**$5**	**$3**	**$97**	**$150**	**$36**	**$48**	**$16**	**$22**	**$126**	**$37**	**$12**	**$24**	**$19**	**$92**	**$95**
FCF/share (diluted)		$0.09	$0.05	$1.29	$1.99	$0.47	$0.64	$0.21	$0.29	$1.66	$0.49	$0.16	$0.31	$0.24	$1.21	$1.25
Operating Free Cash Flow		**($61)**	**$0**	**$77**	**$115**	**$33**	**$47**	**$30**	**$17**	**$128**	**$34**	**$12**	**$24**	**$21**	**$90**	**$106**
Balance Sheet Metrics																
Book Value (per share)		($1.93)	($0.68)	$4.82	$6.85	$7.19	$7.27	$7.23	$7.21	$7.23	$7.21	$7.24	$7.30	$7.37	$7.38	$8.04
Net Debt	**$241**	**$236**	**$236**	**($71)**	**($203)**	**($230)**	**($271)**	**($274)**	**($289)**	**($289)**	**($320)**	**($325)**	**($342)**	**($354)**	**($354)**	**($421)**
Total Debt/Capital	158.2%	173.0%	117.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net Debt/Capital	62.0%	64.0%	54.1%	-32.1%	-182.2%	-280.7%	-4125.5%	-235.0%	879.9%	879.9%	342.8%	320.0%	263.0%	238.9%	238.9%	182.0%
Return on equity		4.9%	-95.4%	91.8%	31.8%	23.1%	5.4%	7.1%	4.4%	10.1%	5.2%	6.9%	8.6%	8.8%	7.4%	13.5%
Return on capital (Net Debt)		**3.8%**	**51.7%**	**61.3%**	**46.2%**	**39.1%**	**10.0%**	**14.0%**	**9.1%**	**18.8%**	**11.8%**	**16.7%**	**21.9%**	**23.5%**	**17.6%**	**40.1%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Core Laboratories (CLB)

The Year Ahead for CLB

It turns out a global pandemic was all that was required to take CLB's previously lofty consensus estimates to more reasonable levels. The stock now trades at an EV/EBITDA of ~13x 2021 EBITDA (v. ~16x 2020 EBITDA this time last year). Year-to-date, CLB shares have fared better than peers (-24% v. -41% OSX) but while exhibiting outsized "oil beta" in our view. Relatively strong free cash flow generation and the prudent decision to cut the dividend to near-zero have provided some much needed headroom on the revised covenant. CLB's improved cost structure and asset light business model can help underwrite its oil-beta to a degree, but if the 2021/2022 macro environment disappoints as we expect it to (especially ex-NAM), we don't think CLB can display the same torque especially with less offshore exploration backlog to fall back on. As a result, we assume this setup will result in lower EBITDA cycle/cycle (JPMe $110mm v. $152mm in '15-'19). With a normalized FCF/EV yield of only ~6.5% (that could takes years to materialize), we are left waiting for a more attractive entry point.

Things to Focus On in 2021

- **Reservoir Description geared up for the (eventual) recovery.** The prior $100mm in revenue per quarter stronghold broke this year as offshore rig operations struggled with stop-and-go operations and project deferrals amid the pandemic. With improved lowered cost structure and asset-light model intact, we think RD margins have the ability to impress on higher activity, but 2021 is still too early. The offshore recovery has once again been pushed out and further detracted by a shift in IOC capital allocation to greener energy. While top line likely troughed in 3Q at $80mm (also hindered by hurricanes in the GOM), we don't model a retracement near the typical $100mm level until the end of 2022. If a lower-for-longer scenario plays out we think management may look for incremental savings following the strong execution YTD. RD remains one of the best businesses in all of OFS, but it needs a better cycle (magnitude and mix) to really show its stuff.
- **Cash-strapped NAM market not as supportive for PE, though an activity ramp underway.** Production Enhancement faces a challenging outlook in 2021 given its sizable (if shrinking) exposure to NAM land completions (~60%). With E&Ps signaling slightly lower spend y/y in 2021 while attempting to keep production flat (v. 4Q20 levels), CLB will benefit from ramping completions q/q in early 2021, allowing EBIT margins to average ~5% (v. near-breakeven in 3Q). Growing market share in the competitive integrated perf gun space remains crucial for CLB, and we think further differentiation can be achieved from leveraging its leading energetics and tracer businesses.
- **Free cash flow providing some covenant headroom.** CLB shouldn't run into any covenant issues in our base case after reporting 2.5x ND/EBITDA in 3Q (+0.3x q/q), compared to the threshold of 3.0x which drops to 2.5x by the end of 2021. FCF generation of $19mm in 3Q brought the YTD total to $61mm with the majority being used to pay down debt. We expect less FCF in 2021 given smaller WC contributions resulting in approximately half a turn of leeway on CLB's adjusted leverage metric by yearend. Manageable, but still dependent on a recovery in oil demand and E&P activity to prevent another accommodation.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 22: Core Laboratories Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Reservoir Description	473	426	415	413	421	103	88	80	83	354	82	83	85	87	336	370
Production Enhancement	267	169	245	288	247	50	27	25	28	130	30	32	35	37	135	145
Reservoir Management	57															
Total Revenue	**$798**	**$595**	**$660**	**$701**	**$668**	**$152**	**$116**	**$105**	**$111**	**$484**	**$111**	**$116**	**$120**	**$123**	**$471**	**$516**
COGS	(533)	(443)	(474)	(497)	(496)	(115)	(91)	(81)	(83)	(369)	(84)	(87)	(90)	(92)	(353)	(381)
SG&A	(50)	(39)	(48)	(52)	(48)	(20)	(9)	(9)	(10)	(47)	(9)	(9)	(9)	(10)	(37)	(38)
Other Expenses	(4)	(0)	1	0	(1)	1	3	(1)	0	3	0	0	0	0	0	0
Total Costs & Expenses	**($586)**	**($482)**	**($521)**	**($549)**	**($545)**	**($134)**	**($97)**	**($91)**	**($92)**	**($414)**	**($93)**	**($96)**	**($99)**	**($101)**	**($390)**	**($419)**
Total D&A	**($27)**	**($27)**	**($25)**	**($23)**	**($23)**	**($5)**	**($5)**	**($5)**	**($5)**	**($21)**	**($5)**	**($5)**	**($5)**	**($5)**	**($21)**	**($21)**
EBITDA	**$216**	**$115**	**$139**	**$155**	**$136**	**$26**	**$16**	**$17**	**$18**	**$78**	**$18**	**$19**	**$21**	**$22**	**$81**	**$97**
Total EBITDA Margin	27.1%	19.3%	21.1%	22.1%	20.3%	17.1%	13.9%	16.6%	16.6%	16.1%	16.3%	16.8%	17.5%	17.8%	17.1%	18.8%
Operating Income																
Reservoir Description	125	80	68	62	68	16	15	12	13	55	12	13	13	14	51	65
Production Enhancement	48	8	46	69	43	4	(5)	(0)	0	(1)	1	1	2	2	7	9
Reservoir Management	16															
Corporate & Other	(0)	0	(0)	1	2	1	0	1	1	2	1	1	1	1	2	2
Total Operating Income Companywide	**$189**	**$88**	**$114**	**$132**	**$113**	**$21**	**$11**	**$12**	**$13**	**$57**	**$13**	**$14**	**$16**	**$17**	**$60**	**$76**
Total Operating Margins	23.6%	14.8%	17.3%	18.8%	16.9%	13.5%	9.2%	11.7%	11.8%	11.7%	11.6%	12.4%	13.2%	13.6%	12.7%	14.7%
Interest Expense	(12)	(12)	(11)	(13)	(15)	(3)	(3)	(5)	(3)	(15)	(3)	(3)	(3)	(3)	(14)	(13)
Other Income	0	0	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	($40)	($10)	($15)	($27)	($20)	($3)	($1)	($0)	($2)	($7)	($2)	($2)	($3)	($3)	($9)	($12)
Tax Rate	*23%*	*14%*	*15%*	*22%*	*20%*	*20%*	*16%*	*4%*	*20%*	*16%*	*20%*	*20%*	*20%*	*20%*	*20%*	*20%*
Net Income	**$115**	**$64**	**$87**	**$79**	**$73**	**($108)**	**($6)**	**$3**	**$8**	**($103)**	**$8**	**$9**	**$10**	**$10**	**$36**	**$50**
Diluted Shares (Avg)	43	44	44	44	45	44	44	45	45	45	45	45	45	45	45	45
EPS (Adjusted, Diluted)	**$3.17**	**$1.51**	**$1.99**	**$2.06**	**$1.74**	**$0.31**	**$0.14**	**$0.16**	**$0.17**	**$0.78**	**$0.17**	**$0.19**	**$0.22**	**$0.23**	**$0.80**	**$1.10**
Dividend per Share	$2.20	$2.20	$2.20	$2.20	$2.20	$0.25	$0.01	$0.01	$0.01	$0.28	$0.01	$0.01	$0.01	$0.01	$0.04	$0.04
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	47	35	(16)	(25)	(8)	(0)	15	15	3	32	1	(2)	(1)	2	(0)	(11)
Cash from Operations	**$219**	**$132**	**$124**	**$112**	**$90**	**$22**	**$27**	**$21**	**$16**	**$86**	**$14**	**$12**	**$14**	**$18**	**$57**	**$60**
Capital Expenditures	($23)	($11)	($19)	($22)	($22)	($3)	($3)	($2)	($2)	($11)	($3)	($2)	($2)	($2)	($10)	($9)
Cash from Investing	**($40)**	**($15)**	**($21)**	**($71)**	**($6)**	**($4)**	**($3)**	**($2)**	**($2)**	**($12)**	**($3)**	**($2)**	**($2)**	**($2)**	**($10)**	**($9)**
Increase (decrease) in Debt	$75	($217)	$10	$64	$15	($3)	($16)	($22)	$0	($41)	$0	$0	$0	$0	$0	$0
Cash from Financing	**($180)**	**($125)**	**($104)**	**($42)**	**($86)**	**($15)**	**($17)**	**($24)**	**($0)**	**($57)**	**($0)**	**($0)**	**($0)**	**($0)**	**($2)**	**($2)**
Cash at End of Period	**$22**	**$15**	**$15**	**$13**	**$11**	**$14**	**$21**	**$15**	**$28**	**$28**	**$39**	**$48**	**$58**	**$73**	**$74**	**$123**
Balance Sheet ($ in millions)																
Total Assets	**$625**	**$573**	**$585**	**$649**	**$775**	**$647**	**$614**	**$591**	**$597**	**$597**	**$605**	**$615**	**$624**	**$634**	**$634**	**$684**
Long-term Debt, Net of Current	**431**	**216**	**227**	**290**	**305**	**302**	**287**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**	**190**
Stockholder Equity	(24)	155	149	161	182	70	66	72	79	79	86	94	103	113	113	161
Cash Flow Metrics																
Free Cash Flow	**$196**	**$121**	**$105**	**$90**	**$67**	**$19**	**$24**	**$19**	**$13**	**$75**	**$11**	**$9**	**$11**	**$15**	**$47**	**$52**
FCF/share (diluted)	$4.58	$2.77	$2.38	$2.02	$1.50	$0.42	$0.54	$0.41	$0.30	$1.67	$0.25	$0.20	$0.25	$0.34	$1.05	$1.14
Operating Free Cash Flow	**$181**	**$120**	**$84**	**$84**	**$66**	**$20**	**$31**	**$24**	**$15**	**$90**	**$10**	**$10**	**$12**	**$16**	**$49**	**$55**
Balance Sheet Metrics																
Book Value (per share)	($0.55)	$3.56	$3.35	$3.62	$4.07	$1.58	$1.49	$1.60	$1.76	$1.77	$1.91	$2.09	$2.29	$2.51	$2.52	$3.56
Net Debt	**$408**	**$202**	**$213**	**$277**	**$294**	**$289**	**$266**	**$249**	**$236**	**$236**	**$225**	**$217**	**$206**	**$191**	**$191**	**$141**
Total Debt/Capital	105.8%	58.2%	60.4%	64.3%	62.6%	81.2%	81.2%	78.7%	77.0%	77.0%	75.5%	73.8%	71.9%	70.0%	70.0%	62.1%
Net Debt/Capital	106.2%	56.5%	58.8%	63.2%	61.8%	80.5%	80.1%	77.7%	75.0%	75.0%	72.4%	69.7%	66.6%	62.8%	62.8%	46.7%
Return on equity	386.9%	100.3%	58.1%	59.2%	45.4%	43.3%	35.7%	42.4%	41.0%	26.6%	36.4%	37.8%	39.4%	38.7%	37.7%	36.2%
Return on capital (Net Debt)	**35.9%**	**20.5%**	**27.1%**	**25.5%**	**19.6%**	**15.7%**	**10.3%**	**14.4%**	**13.0%**	**11.9%**	**13.1%**	**14.5%**	**16.1%**	**17.2%**	**15.2%**	**19.9%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Dril-Quip (DRQ)

The Year Ahead for DRQ

After being the best performer in our coverage in 2019, DRQ's stock has been treated less than kindly since the oil bottom on 3/18 (+3% v. OSX +116%, Capital Equipment peers +167%) despite its defensive nature, strong management team and ballast balance sheet. DRQ has preserved margin through well-executed cost-out, including initiatives to reduce its geographic footprint and R&D spend. Its "win-win" agreement with Proserv contributes to both of these initiatives (future R&D spend reduction of ~$8-10mm is expected) and garnered positive customer feedback so far; we expect more tangible results to become evident in 2021. The bulk of COVID-19 impacts on orders is increasingly in the past (though bookings remain sensitive to timing); while expectations among offshore equipment players remain conservative in 2021, DRQ is one of our best positioned offshore competitors with a strong balance sheet and backlog-driven support to revenue. With an attractive "normalized" yield of +15%, the stock is among the least expensive in our coverage.

Things to Focus On in 2021

- **Monetization of new technology.** DRQ has long emphasized its focus on bringing differentiated technology to market in order to gain traction with IOCs/NOCs, and we expect momentum to increase as operators resume previously delayed activity in 2021. DRQ booked five subsea tree orders in 3Q (including wins in Europe and Asia), and the company remains optimistic about adoption of the VXTe. In 2021, DRQ's differentiated technology can help it gain customer adoption even in the face of stalled offshore activity/orders. Downhole Tools presents another opportunity to increase bookings, with the shorter cycle exposure allowing turnarounds of ~12 weeks. DRQ is also well-suited to take advantage of its expertise in traditional subsea work to be part of the growing energy transition, with opportunities including offshore wind and CCS.

- **Cash preservation remains a focus.** While DRQ indicated it will likely fall just shy of its original goal of achieving cash neutrality in 2020, cash generation in 2021 should come easier as receivables collection improves and more inventory is liquidated. A larger focus on the shorter cycle Downhole Tools segment will likely serve as an important driver of these improvements, along with management's lean techniques for managing inventory.

- **Balance sheet leaves M&A optionality.** DRQ's debt-free balance sheet leaves room for smaller-scale M&A, though the most recent commentary placed more focus (once again) on transformational opportunities. In our view offshore equipment is aching for consolidation (a view DRQ management holds as well); we think the company could be well-positioned to pursue a spin-off acquisition from one of the diversifieds similar to the SLB and LBRT deal. A tuck-in technology acquisition could also help the company further streamline its R&D, boosting the synergies of any such opportunity.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 23: Dril-Quip Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Total Revenue	**$844**	**$539**	**$455**	**$385**	**$415**	**$96**	**$90**	**$91**	**$90**	**$368**	**$86**	**$85**	**$89**	**$88**	**$348**	**$356**
COGS	(459)	(328)	(305)	(271)	(295)	(71)	(67)	(67)	(67)	(272)	(64)	(63)	(65)	(64)	(257)	(254)
SG&A	(93)	(73)	(92)	(92)	(83)	(21)	(20)	(18)	(17)	(76)	(16)	(16)	(16)	(16)	(64)	(61)
Engineering & Product Development	(48)	(44)	(42)	(39)	(17)	(6)	(5)	(4)	(4)	(19)	(4)	(4)	(4)	(4)	(15)	(14)
Total Costs & Expenses	**($600)**	**($446)**	**($439)**	**($403)**	**($395)**	**($98)**	**($92)**	**($89)**	**($88)**	**($367)**	**($84)**	**($83)**	**($85)**	**($84)**	**($336)**	**($329)**
Total D&A	**($30)**	**($32)**	**($41)**	**($35)**	**($34)**	**($9)**	**($8)**	**($8)**	**($7)**	**($32)**	**($7)**	**($7)**	**($7)**	**($7)**	**($27)**	**($25)**
EBITDA	**$274**	**$124**	**$57**	**$17**	**$54**	**$6**	**$6**	**$10**	**$10**	**$32**	**$9**	**$9**	**$10**	**$10**	**$39**	**$51**
EBITDA Margins	32.5%	23.1%	12.6%	4.5%	13.0%	6.7%	6.7%	11.1%	10.7%	8.8%	10.8%	10.9%	11.4%	11.5%	11.2%	14.4%
Total Operating Income Companywide	**$244**	**$93**	**$16**	**($18)**	**$20**	**($2)**	**($2)**	**$2**	**$3**	**$1**	**$2**	**$2**	**$4**	**$4**	**$12**	**$27**
Total Operating Margins	28.9%	17.2%	3.6%	-4.7%	4.8%	-2.5%	-2.1%	2.5%	2.9%	0.1%	2.8%	2.9%	4.0%	4.1%	3.5%	7.5%
Interest Income	1	3	4	8	8	1	1	0	0	2	0	0	0	0	0	2
Interest Expense	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	($57)	($19)	($6)	($13)	($24)	$0	($11)	$13	($1)	$1	($1)	($1)	($1)	($1)	($5)	($12)
Tax Rate	*23%*	*20%*	*33%*	*-131%*	*88%*	*5%*	*-743%*	*-566%*	*40%*	*-49%*	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*
Net Income	**$188**	**$76**	**$7**	**($23)**	**$3**	**($1)**	**($12)**	**$15**	**$2**	**$3**	**$1**	**$1**	**$2**	**$2**	**$7**	**$17**
Diluted Shares (Avg)	39	38	38	37	36	36	35	35	35	35	35	35	35	35	35	35
EPS (Adjusted, Diluted)	**$4.87**	**$2.02**	**$0.35**	**($0.63)**	**$0.09**	**($0.04)**	**($0.35)**	**$0.44**	**$0.05**	**$0.10**	**$0.04**	**$0.04**	**$0.06**	**$0.06**	**$0.20**	**$0.50**
Dividend per Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Additional Details																
Total Backlog	**$685**	**$318**	**$207**	**$270**	**$272**	**$261**	**$238**	**$222**	**$210**	**$210**	**$198**	**$190**	**$182**	**$178**	**$178**	**$206**
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	(42)	113	76	4	(34)	(43)	(11)	(12)	12	(53)	62	2	(11)	(7)	45	55
Cash from Operations	**$190**	**$247**	**$108**	**$46**	**$15**	**($21)**	**$3**	**$14**	**$28**	**$17**	**$70**	**$11**	**($3)**	**$1**	**$80**	**$98**
Capital Expenditures	($27)	($26)	($28)	($32)	($12)	($4)	($4)	($2)	($3)	($13)	($3)	($3)	($3)	($3)	($11)	($11)
Cash from Investing	**($27)**	**($158)**	**($45)**	**($15)**	**($8)**	**($4)**	**($2)**	**($1)**	**($3)**	**($9)**	**($3)**	**($3)**	**($3)**	**($3)**	**($11)**	**($11)**
Increase (decrease) in LT Debt	$0	$0	$0	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash from Financing	**($74)**	**($22)**	**$1**	**($100)**	**($25)**	**($25)**	**($0)**	**($0)**	**$0**	**($25)**	**$0**	**$0**	**$0**	**$0**	**$0**	**($8)**
Cash at End of Period	**$381**	**$424**	**$493**	**$418**	**$399**	**$343**	**$346**	**$359**	**$384**	**$384**	**$452**	**$459**	**$454**	**$452**	**$452**	**$531**
Balance Sheet ($ in millions)																
Total Assets	**$1,428**	**$1,461**	**$1,400**	**$1,193**	**$1,207**	**$1,136**	**$1,148**	**$1,160**	**$1,167**	**$1,167**	**$1,167**	**$1,167**	**$1,170**	**$1,171**	**$1,171**	**$1,175**
Long-term Debt, Net of Current	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Stockholder Equity	1,324	1,356	1,295	1,096	1,091	1,024	1,015	1,038	1,046	1,046	1,048	1,049	1,051	1,053	1,053	1,063
Cash Flow Metrics																
Free Cash Flow	**$163**	**$221**	**$80**	**$13**	**$3**	**($25)**	**($1)**	**$12**	**$25**	**$4**	**$67**	**$8**	**($6)**	**($2)**	**$68**	**$87**
FCF/share (diluted)	$4.21	$5.86	$2.13	$0.37	$0.08	($0.71)	($0.03)	$0.34	$0.71	$0.30	$1.91	$0.22	($0.16)	($0.05)	$1.93	$2.47
Operating Free Cash Flow	**$270**	**$168**	**$118**	**$54**	**($22)**	**$14**	**($9)**	**$9**	**$18**	**$32**	**$67**	**$8**	**($6)**	**($2)**	**$68**	**$84**
Balance Sheet Metrics																
Book Value (per share)	$34.35	$36.00	$34.33	$29.46	$30.47	$28.69	$28.99	$29.44	$29.68	$29.63	$29.72	$29.76	$29.82	$29.88	$29.88	$30.29
Net Debt	**($381)**	**($387)**	**($493)**	**($418)**	**($399)**	**($343)**	**($346)**	**($359)**	**($384)**	**($384)**	**($452)**	**($459)**	**($454)**	**($452)**	**($452)**	**($531)**
Total Debt/Capital	0.0%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net Debt/Capital	-40.4%	-40.0%	-61.5%	-61.7%	-57.7%	-50.5%	-51.6%	-52.9%	-58.0%	-58.0%	-75.8%	-77.9%	-76.0%	-75.2%	-75.2%	-99.9%
Return on equity	14.6%	5.7%	1.0%	-2.0%	0.3%	-0.5%	-4.8%	6.0%	0.7%	0.3%	0.6%	0.6%	0.8%	0.8%	0.7%	1.6%
Return on capital (Net Debt)	**20.0%**	**8.2%**	**1.8%**	**-0.5%**	**0.6%**	**-1.3%**	**-9.5%**	**8.9%**	**0.9%**	**1.2%**	**0.9%**	**1.0%**	**1.4%**	**1.4%**	**1.1%**	**3.3%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Halliburton (HAL)

The Year Ahead for HAL

Halliburton's shares have been among the better performers in our coverage group YTD (-18% v. -43% SLB, -14% BKR, OSX -41%) as investors have been quick to reward the company off the March trough for its strategic shift and cost control measures to defend margins in a challenging environment, as well as for a less dire NAM outlook. HAL completed its ~$1bn cost-out program by the end of 3Q20 and showed success in reducing much of the "low-calorie" work in C&P. Heading into 2021, we think C&P growth prospects are relatively good as NAM completions work is set to recover in 1H21, but in D&C the higher international mix will moderate growth from the 4Q20 exit as we anticipate a slow recovery in activity outside of NAM. HAL's efforts to ramp up its "Halliburton 4.0" suite of digitally-enabled technology will be key to driving further cost savings for the company next year and delivering the technology to unlock incremental efficiencies for customers. We believe capital efficiency will help Halliburton deliver solid FCF in 2021 (JPMe ~$850mm), but following the post-election surge (HAL +76% since 10/28 v. SLB +62%, OSX +77%) valuation looks full on a normalized basis, raising the bar for 2021. The setup is reminiscent of 2016's turn to 2017, leaving us cautious.

Things to Focus On in 2021

- **Anticipate C&P top line expansion on NAM recovery; cost management puts margin bogey within reach.** HAL demonstrated that it was "walking the walk" on its efforts to reduce costs and reorient toward "high-calorie" work in C&P, evidenced by the segment's recovery to ~13.5% operating margin in 3Q20 (v. ~9.5% trough in 2Q20, aided by asset write-downs as well). We expect C&P to lead top line growth for HAL in 2021, driven by our anticipated rise in NAM completions in 1H21. With this ramp, we think Halliburton can reach its 15% "normalized" operating margin bogey by 4Q21. Investors should also be focused on technological initiatives HAL is pursuing to differentiate itself from NAM frac providers, including SmartFleet, further adoption of simul-fracs and an in-house e-frac solution (we expect more announcements to come on the topic in 2021).
- **D&E growth looks modest in 2021 on slow international recovery, keeping margins at HSD.** D&E operating margin proved disappointing in 2020, falling to ~7.5% in 3Q20 (from ~10.5% in 1Q20). Though this most recent level is likely the trough, we expect only modest gains to D&E top line and margin in 2021. We anticipate the international activity recovery will be slower than the one seen in NAM, and with international operator spending likely even more back half-weighted in 2021 than just typical seasonality would suggest, leaves limited growth opportunities until later next year. While improved activity should help grow margins q/q, we model 2021 operating margin staying in the 7-9% range.
- **Cash flow can remain strong on good capital efficiency.** HAL was able to deliver solid FCF this year ($733mm YTD, guidance of +$1bn for FY2020) due in large part to its ability to "squeeze the rag" on working capital. Though this WC benefit will dissipate in 2021, we think capital efficiency efforts (capex guided to be 5-6% of revenue, the lower end of the prior range of 5-7%), less cash costs tied to restructuring, and growing EBITDA, can all conspire to help Halliburton deliver respectable FCF next year (JPMe ~$850mm). Our estimate implies that HAL's 2021 cash generation should be sufficient to cover the dividend ($160mm) and its 2021 debt maturities ($685mm).

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 24: Halliburton Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Completion & Production	13,721	8,882	13,077	15,973	14,031	2,962	1,672	1,574	1,733	7,941	1,895	2,065	2,213	2,196	8,369	8,976
Drilling & Evaluation	9,912	7,005	7,543	8,022	8,377	2,075	1,524	1,401	1,478	6,478	1,470	1,510	1,557	1,555	6,092	6,570
Total Revenue	**$23,633**	**$15,887**	**$20,620**	**$23,995**	**$22,408**	**$5,037**	**$3,196**	**$2,975**	**$3,211**	**$14,419**	**$3,365**	**$3,575**	**$3,769**	**$3,751**	**$14,461**	**$15,545**
Total D&A	($1,835)	($1,503)	($1,556)	($1,606)	($1,625)	($348)	($251)	($230)	($228)	($1,057)	($227)	($227)	($226)	($226)	($906)	($899)
EBITDA	**$4,156**	**$2,194**	**$3,565**	**$4,338**	**$3,683**	**$850**	**$487**	**$505**	**$528**	**$2,370**	**$558**	**$600**	**$638**	**$634**	**$2,431**	**$2,640**
Operating Income																
Completion & Production	$1,082	$107	$1,621	$2,278	$1,671	$345	$159	$212	$234	$950	$267	$301	$330	$327	$1,225	$1,346
Drilling & Evaluation	1,506	794	718	745	642	217	127	105	116	565	114	122	132	131	500	596
Corporate & Other Income	(267)	(210)	(330)	(291)	(255)	(60)	(50)	(42)	(50)	(202)	(50)	(50)	(50)	(50)	(200)	(200)
Total Operating Income Companywide	**$2,321**	**$691**	**$2,009**	**$2,732**	**$2,058**	**$502**	**$236**	**$275**	**$300**	**$1,313**	**$331**	**$373**	**$412**	**$408**	**$1,525**	**$1,741**
Completion & Production	7.9%	1.2%	12.4%	14.3%	11.9%	11.6%	9.5%	13.5%	13.5%	12.0%	14.1%	14.6%	14.9%	14.9%	14.6%	15.0%
Drilling & Evaluation	15.2%	11.3%	9.5%	9.3%	7.7%	10.5%	8.3%	7.5%	7.8%	8.7%	7.8%	8.1%	8.5%	8.5%	8.2%	9.1%
Total Operating Margins	**9.8%**	**4.3%**	**9.7%**	**11.4%**	**9.2%**	**10.0%**	**7.4%**	**9.2%**	**9.4%**	**9.1%**	**9.8%**	**10.4%**	**10.9%**	**10.9%**	**10.5%**	**11.2%**
Income Taxes	($448)	$93	($376)	($416)	($300)	($73)	($16)	($32)	($21)	($142)	($36)	($45)	($53)	($54)	($189)	($229)
Tax Rate	*25%*	*81%*	*26%*	*20%*	*22%*	*21%*	*25%*	*24%*	*15%*	*21%*	*21%*	*21%*	*21%*	*21%*	*21%*	*20%*
Net Income	**($669)**	**($5,761)**	**($444)**	**$1,656**	**($1,133)**	**($1,017)**	**($1,676)**	**($21)**	**$120**	**($2,594)**	**$136**	**$169**	**$200**	**$202**	**$707**	**$938**
Diluted Shares (Avg)	854	862	871	877	876	878	877	882	883	880	884	885	886	887	886	890
EPS (Adjusted, Diluted)	**$1.56**	**($0.02)**	**$1.22**	**$1.89**	**$1.23**	**$0.31**	**$0.05**	**$0.11**	**$0.14**	**$0.61**	**$0.15**	**$0.19**	**$0.23**	**$0.23**	**$0.80**	**$1.05**
Dividend per Share	$0.72	$0.72	$0.72	$0.72	$0.72	$0.18	$0.05	$0.05	$0.05	$0.32	$0.05	$0.05	$0.05	$0.05	$0.18	$0.18
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	$422	$1,013	($319)	($384)	($161)	($200)	$253	$180	$256	$489	$62	($9)	$36	($78)	$11	($112)
Cash from Operations	**$2,906**	**($1,703)**	**$2,468**	**$3,157**	**$2,445**	**$225**	**$598**	**$420**	**$537**	**$1,780**	**$423**	**$384**	**$459**	**$347**	**$1,614**	**$1,725**
Capital Expenditures	($2,184)	($798)	($1,373)	($2,026)	($1,530)	($213)	($142)	($155)	($241)	($751)	($177)	($188)	($198)	($197)	($759)	($816)
Cash from Investing	**($2,192)**	**($710)**	**($1,927)**	**($1,993)**	**($1,445)**	**($165)**	**($116)**	**($63)**	**($241)**	**($585)**	**($177)**	**($188)**	**($198)**	**($197)**	**($759)**	**($816)**
Increase (decrease) in LT Debt	$7,440	($3,097)	($1,641)	($445)	$0	($657)	($2)	$0	$0	($659)	($185)	$0	$0	($500)	($685)	$0
Cash from Financing	**$7,081**	**($3,540)**	**($2,161)**	**($1,419)**	**($695)**	**($903)**	**($34)**	**($35)**	**($40)**	**($1,012)**	**($225)**	**($40)**	**($40)**	**($540)**	**($844)**	**($160)**
Cash at End of Period	**$10,077**	**$4,009**	**$2,337**	**$2,008**	**$2,268**	**$1,385**	**$1,811**	**$2,115**	**$2,372**	**$2,372**	**$2,393**	**$2,550**	**$2,771**	**$2,382**	**$2,382**	**$3,131**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (Net)	10,911	8,532	8,521	8,961	7,310	6,223	5,156	5,033	5,046	5,046	4,996	4,956	4,928	4,899	4,899	4,816
Total Assets	**$36,942**	**$27,005**	**$25,085**	**$26,063**	**$25,377**	**$23,622**	**$21,104**	**$20,874**	**$21,046**	**$21,046**	**$20,970**	**$21,174**	**$21,364**	**$20,980**	**$20,980**	**$21,838**
Long-term Debt, Net of Current	**14,687**	**12,214**	**10,430**	**10,421**	**10,316**	**9,633**	**9,638**	**9,632**	**9,632**	**9,632**	**9,447**	**9,447**	**9,447**	**8,947**	**8,947**	**8,947**
Stockholder Equity	15,462	9,384	8,349	9,544	8,025	6,843	5,196	5,203	5,217	5,217	5,310	5,437	5,594	5,753	5,753	6,532
Cash Flow Metrics																
Free Cash Flow	**$722**	**($2,501)**	**$1,095**	**$1,131**	**$915**	**$12**	**$456**	**$265**	**$296**	**$1,029**	**$246**	**$197**	**$261**	**$150**	**$854**	**$909**
FCF/share (diluted)	$0.85	($2.90)	$1.26	$1.29	$1.05	$0.01	$0.52	$0.30	$0.34	$1.17	$0.28	$0.22	$0.29	$0.17	$0.96	$1.02
Balance Sheet Metrics																
Book Value (per share)	$18.10	$10.89	$9.59	$10.88	$9.17	$7.79	$5.92	$5.90	$5.91	$5.93	$6.01	$6.14	$6.31	$6.49	$6.50	$7.34
Net Debt	**$5,269**	**$8,368**	**$8,605**	**$9,127**	**$8,652**	**$8,441**	**$8,015**	**$7,712**	**$7,455**	**$7,455**	**$7,249**	**$7,092**	**$6,871**	**$6,760**	**$6,760**	**$6,011**
Total Debt/Capital	49.8%	56.9%	56.7%	53.8%	57.6%	58.9%	65.4%	65.4%	65.3%	65.3%	64.5%	63.9%	63.3%	61.4%	61.4%	58.3%
Net Debt/Capital	25.4%	47.1%	50.8%	48.9%	51.9%	55.2%	60.7%	59.7%	58.8%	58.8%	57.7%	56.6%	55.1%	54.0%	54.0%	47.9%
Return on equity	8.4%	(0.1%)	12.0%	18.6%	12.3%	14.5%	3.1%	7.7%	9.2%	8.1%	10.3%	12.6%	14.5%	14.2%	12.9%	15.3%
Return on capital (Net Debt)	**7.7%**	**0.5%**	**8.2%**	**11.8%**	**8.6%**	**9.4%**	**3.9%**	**5.9%**	**7.2%**	**6.4%**	**7.5%**	**8.6%**	**9.6%**	**9.5%**	**8.8%**	**10.4%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Helmerich & Payne (HP)

The Year Ahead for HP

HP's U.S. activity experienced a deeper trough than peers PTEN and NBR during 2020 as it saw its rig count decline -53% q/q in CY2Q (v. -50% for the BKR L-48 rig count, -33%/-36% PTEN/NBR). However the company demonstrated in its latest update that it can recoup much of the market share it has lost (i.e. a higher "beta" fleet), guiding to exit CY2020 with ~90 rigs contracted, nearly double its lowest point during the year. We think H&P will continue to be able to outpace peers in adding incremental rigs in CY2021 and can grow its L-48 market share to ~30%. While U.S. day margins appear to have bottomed at ~$4.5k/d (better than the $0-3k/d range some investors feared), international profitability looks severely impaired near-term as activity has dwindled. H&P cut its quarterly dividend -65% to $0.25/sh (from $0.71/sh) in 2020, but is committed to holding the current level even if it cannot be covered by FCF in certain periods. HP has the balance sheet strength to do so which, combined with the company's elevated L-48 drilling "beta" and attractive technology suite, makes it our preferred stock among our land drilling coverage.

Things to Focus On in CY2021

- **NAM Solutions: reclaiming "lost" market share, furthering technology penetration, and defending margin.** After seeing outsized rig drops in CY2Q/3Q, H&P claims it should be able to recoup its market share as customers ramp drilling programs. HP demonstrated as much so far in CY4Q, guiding to a q/q rig increase of +20-25%, outpacing commentary from peers PTEN and NBR. We think HP will be able to continue expanding its L-48 market share in CY2021 to ~30%, driven in part by the value proposition of its technology offerings. Furthering penetration of AutoSlide and other drilling tech will not only help differentiate HP in winning contracts, but should support margins as the company layers more performance-based agreements, crucial for profitability as average pricing resets lower as more recently-signed, spot-based agreements are added.
- **International Solutions activity and margins to languish.** H&P is down to only three international rigs working currently (all in Bahrain), from ~17 at the beginning of CY2020. The company presently has no line of sight to bringing other rigs back online near-term. We think HP can add some incremental rigs in CY2H21 as drilling activity likely rebounds in MENA and LatAm, but still model only a MSD-HSD number of active rigs at the end of CY2021. Margins are likely to suffer as a result with such a small base of active rigs across which to spread costs. Additional rig adds will eventually help lift international gross margin from the -$5-7mm guided for CY4Q20, but we don't think positive gross margin in the segment is achievable until CY2022.
- **HP needs to show a pathway to FCF in excess of the dividend.** FCF remained strong in FY2020, thanks in large part to unwinding AR during the activity decline. However we model a tougher road ahead for cash generation in FY2021 as WC normalizes and margins remain challenged, and HP maintains a cost structure intended for a normalized rig count meaningfully higher than today's level. Though HP has ample liquidity to continue funding the dividend while FCF dips into negative territory (cash of $488mm and $750mm available on its undrawn RCF), given our drilling demand outlook we think it's still a tall order for HP to generate cash of ~$108mm to cover the dividend in FY2021/2022. We believe HP's ability to show a clear avenue to generating FCF above this level is key to the stock's performance, especially with the bar raised exiting 2020.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 25: Helmerich & Payne Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
North America Solutions	$1,794	$937	$1,618	$2,234	$2,319	$536	$204	$138	$170	$1,047	$210	$226	$237	$242	$914	$1,127
Offshore Gulf of Mexico	213	131	136	146	151	33	37	32	29	132	29	29	29	30	117	135
International Solutions	352	221	197	237	194	51	22	24	12	109	10	17	20	23	71	170
H&P Technologies				18	52	18	0	0	0	18	0	0	0	0	0	0
Other	14	12	19	36	13	3	3	3	3	12	3	3	3	3	11	11
Total Revenue	**$2,374**	**$1,301**	**$1,969**	**$2,671**	**$2,729**	**$623**	**$267**	**$197**	**$213**	**$1,318**	**$252**	**$275**	**$289**	**$297**	**$1,113**	**$1,443**
COGS	(1425)	(836)	(1364)	(1767)	(1705)	(428)	(207)	(164)	(168)	(966)	(198)	(214)	(225)	(230)	(866)	(1092)
SG&A	(134)	(141)	(160)	(209)	(190)	(42)	(43)	(33)	(40)	(157)	(36)	(38)	(38)	(36)	(149)	(138)
Total Costs & Expenses	(1567)	(984)	(1537)	(1999)	(1938)	(477)	(253)	(202)	(215)	(1147)	(241)	(260)	(270)	(274)	(1045)	(1263)
Total D&A	(582)	(552)	(544)	(550)	(538)	(131)	(110)	(110)	(107)	(460)	(107)	(107)	(108)	(106)	(429)	(427)
EBITDA	**$813**	**$313**	**$423**	**$657**	**$743**	**$142**	**$14**	**($5)**	**($2)**	**$152**	**$10**	**$16**	**$19**	**$23**	**$68**	**$180**
Total Operating Income Companywide	**$231**	**($239)**	**($121)**	**$106**	**$205**	**$12**	**($96)**	**($115)**	**($109)**	**($308)**	**($97)**	**($92)**	**($88)**	**($84)**	**($361)**	**($247)**
Total Operating Margins	10%	-18%	-6%	4%	8%	2%	-36%	-58%	-51%	-23%	-39%	-33%	-31%	-28%	-32%	-17%
Income Taxes	(73)	105	38	(42)	(23)	(9)	14	29	18	52	18	17	17	16	68	48
Tax Rate	*34%*	*39%*	*28%*	*44%*	*12%*	*104%*	*13%*	*24%*	*16%*	*16%*	*18%*	*18%*	*18%*	*18%*	*18%*	*18%*
Net Income	**$234**	**($110)**	**$402**	**($7)**	**($22)**	**($421)**	**($46)**	**($59)**	**($96)**	**($621)**	**($83)**	**($79)**	**($76)**	**($72)**	**($310)**	**($218)**
Diluted Shares (Avg)	108	108	109	109	109	109	107	107	108	108	108	108	108	108	108	108
EPS (Adjusted, diluted)	**$1.33**	**($1.49)**	**($0.88)**	**$0.50**	**$1.52**	**($0.00)**	**($0.85)**	**($0.86)**	**($0.89)**	**($2.60)**	**($0.77)**	**($0.73)**	**($0.71)**	**($0.67)**	**($2.88)**	**($2.02)**
Dividend per Share	$2.77	$2.78	$2.80	$2.83	$2.84	$0.71	$0.71	$0.25	$0.25	$1.92	$0.25	$0.25	$0.25	$0.25	$1.00	$1.00
Additional Information																
U.S. Land Drilling																
Revenue Days	60,456	34,823	65,698	81,551	77,557	17,273	8,101	5,945	7,475	38,794	8,629	9,423	10,002	10,202	38,256	46,614
Day Rate	26.7	24.7	21.9	23.9	25.7	25.7	21.8	22.0	21.5	22.7	21.1	20.9	20.6	20.6	20.8	21.0
Day Cost	(13.6)	(14.0)	(14.3)	(14.4)	(15.0)	(15.9)	(15.4)	(17.3)	(15.8)	(16.1)	(15.3)	(15.0)	(14.9)	(14.9)	(15.0)	(14.6)
Day Margin	13.1	10.7	7.6	9.5	10.7	9.8	6.4	4.6	5.8	6.6	5.8	5.9	5.7	5.7	5.8	6.4
Offshore Drilling																
Revenue Days	2,994.0	2,616.0	2,092.0	2,101.0	2,188.0	457.0	455.0	460.0	368.0	1,740.0	360.0	364.0	368.0	368.0	1,460.0	1,782.0
Day Rate	36.8	27.9	35.6	35.2	39.5	42.1	49.7	45.3	48.9	46.5	48.4	47.9	47.9	47.9	48.0	48.2
Day Cost	(23.2)	(19.2)	(23.9)	(26.3)	(29.8)	(49.7)	(34.7)	(37.6)	(36.5)	(39.6)	(36.1)	(35.7)	(35.4)	(35.4)	(35.6)	(35.8)
Day Margin	13.5	8.7	11.7	8.9	9.6	(7.6)	15.0	7.7	12.4	6.9	12.3	12.2	12.5	12.5	12.4	12.4
Rig Utilization	91%	80%	71%	73%	75%	63%	63%	63%	50%	60%	50%	50%	50%	50%	50%	61%
International Land																
Revenue Days	6,805.0	5,110.0	4,931.0	6,868.0	6,286.0	1,547.0	988.0	452.0	277.2	3,264.2	271.2	453.0	548.4	644.9	1,917.5	4,914.0
Day Rate	45.9	40.3	37.9	32.6	29.2	31.6	19.6	46.0	36.8	33.5	36.8	35.7	35.3	33.6	35.3	32.9
Day Cost	(35.0)	(30.5)	(28.8)	(23.3)	(21.0)	(21.5)	(21.6)	(42.8)	(58.2)	(36.0)	(58.2)	(43.1)	(39.6)	(35.7)	(44.2)	(31.4)
Day Margin	10.9	9.9	9.1	9.3	8.1	10.1	(1.9)	3.2	(21.4)	(2.5)	(21.4)	(7.4)	(4.3)	(2.1)	(8.8)	1.5
Rig Utilization	48%	37%	40%	53%	55%	53%	34%	15%	9%	38%	9%	15%	18%	21%	17%	42%
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	405	(48)	43	34	56	(68)	153	104	(6)	182	(18)	(0)	10	(14)	(22)	(30)
Cash from Operations	**$1,337**	**$516**	**$567**	**$682**	**$758**	**$121**	**$214**	**$93**	**($5)**	**$422**	**$6**	**$28**	**$42**	**$20**	**$96**	**$179**
Capital expenditures	(879)	(225)	(407)	(571)	(308)	(48)	(27)	(20)	(23)	(118)	(24)	(25)	(25)	(23)	(98)	(150)
Cash from Investing	**($905)**	**($206)**	**($492)**	**($530)**	**($259)**	**($24)**	**($40)**	**($1)**	**($16)**	**($80)**	**($17)**	**($17)**	**($18)**	**($16)**	**($68)**	**($120)**
Increase (decrease) in Debt	451	(41)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash from Financing	**$153**	**($333)**	**($309)**	**($314)**	**($367)**	**($111)**	**($78)**	**($31)**	**($27)**	**($247)**	**($27)**	**($27)**	**($27)**	**($27)**	**($108)**	**($108)**
Cash at End of Period	**$848**	**$826**	**$384**	**$228**	**$360**	**$341**	**$436**	**$497**	**$449**	**$455**	**$412**	**$396**	**$393**	**$370**	**$376**	**$327**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	5,531	5,103	4,950	4,900	4,412	3,840	3,754	3,646	3,562	3,562	3,479	3,396	3,314	3,231	3,231	2,955
Total Assets	**$7,130**	**$6,678**	**$6,362**	**$6,144**	**$5,842**	**$5,177**	**$4,962**	**$4,830**	**$4,707**	**$4,707**	**$4,613**	**$4,525**	**$4,440**	**$4,350**	**$4,350**	**$4,080**
Long-term Debt, Net of Current	493	492	493	491	479	480	480	481	481	481	481	481	481	481	481	481
Stockholder Equity	4,830	4,476	4,590	4,326	3,976	3,461	3,396	3,319	3,203	3,203	3,101	3,003	2,907	2,815	2,815	2,519
Cash Flow Metrics																
Free Cash Flow	**$458**	**$291**	**$160**	**$111**	**$450**	**$73**	**$187**	**$73**	**($28)**	**$304**	**($18)**	**$3**	**$16**	**($3)**	**($2)**	**$29**
FCF/share (diluted)	4.23	2.69	1.47	1.02	4.12	0.67	1.74	0.68	(0.26)	2.82	(0.17)	0.03	0.15	(0.03)	(0.02)	0.27
Operating Free Cash Flow	**($430)**	**$106**	**$239**	**$38**	**$348**	**$51**	**($126)**	**($120)**	**($2)**	**($194)**	**$20**	**$3**	**$1**	**$19**	**$43**	**$88**
Balance Sheet Metrics																
Book Value (per share)	$45	$41	$42	$40	$36	$32	$32	$31	$30	$30	$29	$28	$27	$26	$26	$23
Net Debt	**($316)**	**($334)**	**$110**	**$262**	**$124**	**$144**	**$54**	**($7)**	**$40**	**$40**	**$77**	**$94**	**$97**	**$120**	**$120**	**$168**
Total Debt/Capital	9.9%	9.9%	9.7%	10.2%	10.8%	12.2%	12.4%	12.7%	13.0%	13.0%	13.4%	13.8%	14.2%	14.6%	14.6%	16.0%
Net Debt/Capital	(7.0%)	(8.1%)	2.3%	5.7%	3.0%	4.0%	1.6%	(0.2%)	1.2%	1.2%	2.4%	3.0%	3.2%	4.1%	4.1%	6.3%
Return on equity	3.0%	(3.5%)	(2.1%)	1.2%	4.0%	(0.0%)	(10.6%)	(11.0%)	(11.8%)	(7.8%)	(10.5%)	(10.3%)	(10.3%)	(10.1%)	(10.3%)	(8.2%)
Return on capital (Net Debt)	**3.4%**	**(3.4%)**	**(1.8%)**	**1.4%**	**4.3%**	**(0.1%)**	**(9.7%)**	**(10.4%)**	**(11.1%)**	**(7.1%)**	**(9.8%)**	**(9.4%)**	**(9.4%)**	**(9.1%)**	**(9.4%)**	**(7.1%)**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Liberty Oilfield Services (LBRT)

The Year Ahead for LBRT

Liberty's business is set to expand materially in 2021 with the acquisition of OneStim from SLB. The combined company will be the second-largest NAM frac provider with ~2.5mm available hp, and the merger will expand Liberty's operations into all major shale basins (including dry-gas plays for the first time) as well as pump-down perforating and Permian sand mines. For our part we think 1) the expansion of Liberty's operating base at an attractive valuation and 2) forming a partnership with Schlumberger for technology initiatives sets LBRT up for further success this cycle. Liberty has established itself as the technology leader within NAM frac, and with operators looking to partner with those that can provide the most value, we think its fleets will be among the most sought-after in 2021. We like Liberty's clean balance sheet and upside potential through operating leverage to ramp up margins in a bullish activity scenario, but as the second-best performing stock in our coverage YTD (+1% v. OSX -41%, peers -31%), the valuation looks rather full to us.

Things to Focus On in 2021

- **Integration of OneStim fleets.** Liberty estimates it needs to invest $5-10mm per legacy SLB fleet in order to "Libertize" them. We expect more than half of these investments to be made in 2021, likely elevating near-term capex, though LBRT may flex the timing depending on its activity expectations. For our part we imagine the 1.25mm hp retained from Schlumberger is well-maintained, high-quality equipment that will perform up to the LBRT standard once conversion investments have been made. Profit/fleet will be a closely-watched metric.
- **Potential e-frac expansion, and continued conventional tech development.** Liberty has established itself at the forefront of frac technology, and it stands to reason that it would seek to forge a leadership position in electric frac as well. The company is conducting research into e-frac solutions, and we would not be surprised to hear plans from LBRT to pursue an e-frac option sometime in 2021. In the meantime, Liberty has an extensive fleet of dual fuel-capable, Tier IV DGB-powered spreads to offer to ESG-minded customers, and continues to invest in other technology geared toward its conventional fleets.
- **Strong market share position and upside potential from operating leverage.** On our recent Denver Energy Tour, Liberty floated an average of 200-250 active fleets needed in the L-48 for U.S. crude production to remain flat (v. 4Q20 levels) or modestly grow, slightly higher than our normalized estimates. Whatever the ultimate count ends up being, we think LBRT can meet or exceed the ~20% market share historically held by LBRT+SLB. Should frac demand outpace our estimates, we think Liberty can deploy additional fleets with minimal incremental costs, capitalizing on its high operating leverage to drive profitability higher. In our base case however, we see annualized EBITDA fleet returning to HSD $mm in 2H21, similar to 1Q20 levels.
- **"Libertization" capital needs weigh on near-term FCF, but set up longer-term success.** We model a fairly heavy capex spend of ~$225mm in 2021 due to ~$150mm for "Libertization" upgrades, ~$95mm for maintenance costs, and ~$25mm for reactivations and tech investments, offset by a ~$40mm benefit from cannibalizing old SLB equipment. Given this relatively elevated spend, we see FCF likely hovering around breakeven in 2021. However, we note LBRT has flex in how/when it deploys this capital, and the $40mm recovery is likely low. In any case, fleet standardization is the right move in our view, irrespective of timing.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 26: Liberty Oilfield Services Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement (C$ in millions)																
Total Revenue	**$455**	**$375**	**$1,490**	**$2,155**	**$1,990**	**$472**	**$88**	**$147**	**$185**	**$894**	**$534**	**$649**	**$685**	**$647**	**$2,514**	**$2,770**
COGS	(394)	(350)	(1147)	(1629)	(1621)	(393)	(90)	(139)	(167)	(788)	(468)	(553)	(575)	(545)	(2141)	(2307)
SG&A	(29)	(35)	(79)	(99)	(98)	(29)	(18)	(19)	(17)	(83)	(24)	(24)	(25)	(24)	(97)	(93)
Total Costs & Expenses	(423)	(386)	(1226)	(1728)	(1719)	(421)	(108)	(158)	(184)	(871)	(492)	(577)	(600)	(569)	(2238)	(2401)
Total D&A	(36)	(41)	(81)	(125)	(165)	(45)	(45)	(44)	(46)	(181)	(64)	(66)	(68)	(70)	(268)	(298)
EBITDA	**$41**	**($4)**	**$281**	**$438**	**$277**	**$54**	**($13)**	**($3)**	**$2**	**$39**	**$42**	**$72**	**$84**	**$78**	**$277**	**$370**
EBITDA Margins	9%	-1%	19%	20%	14%	11%	-14%	-2%	1%	4%	8%	11%	12%	12%	11%	13%
Total Operating Income Companywide	**$4**	**($46)**	**$199**	**$313**	**$112**	**$9**	**($74)**	**($48)**	**($45)**	**($157)**	**($22)**	**$7**	**$16**	**$8**	**$9**	**$71**
Total Operating Margins	**1%**	**-12%**	**13%**	**15%**	**6%**	**2%**	**-83%**	**-32%**	**-24%**	**-18%**	**-4%**	**1%**	**2%**	**1%**	**0%**	**3%**
EBIT Margins	1%	-12%	13%	15%	6%	2%	-83%	-32%	-24%	-18%	-4%	1%	2%	1%	0%	3%
Income Taxes	(3)	(2)	(6)	(44)	(16)	(1)	11	8	7	25	4	(1)	(2)	(1)	0	(9)
Tax Rate	*-236%*	*-4%*	*3%*	*15%*	*16%*	*17%*	*14%*	*16%*	*14%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*	*15%*
Net Income	**($9)**	**($59)**	**$169**	**$126**	**$39**	**$2**	**($48)**	**($35)**	**($42)**	**($122)**	**($20)**	**$4**	**$12**	**$4**	**($0)**	**$50**
Diluted Shares (Avg)		69	69	118	105	115	83	85	85	92	150	150	150	150	150	150
As Converted EPS (Adjusted, Diluted)		**($0.79)**	**$2.62**	**$1.90**	**$0.68**	**$0.03**	**($0.71)**	**($0.46)**	**($0.44)**	**($1.58)**	**($0.12)**	**$0.02**	**$0.07**	**$0.03**	**($0.00)**	**$0.30**
Dividend per Share		$0.00	$0.00	$0.10	$0.20	$0.05	$0.00	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Metrics	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Active Frac Fleets		7	15	21	23	23	5	9	11	12	28	34	36	35	33	36
% Frac Utilization		**$1**	**$1**	**$1**	**$1**	**$1**	**$0**	**$0**	**$1**	**$1**	**$1**	**$1**	**$1**	**$1**	**$1**	**$1**
Total Frac Fleets		8	16	22	23	24	24	24	24	24	52	52	52	52	52	52
Average Revenue per Active Fleet		**$51**	**$97**	**$101**	**$87**	**$83**	**$77**	**$63**	**$65**	**$74**	**$73**	**$74**	**$74**	**$71**	**$76**	**$77**
EBITDA per Active Fleet (annualized)		**($1)**	**$18**	**$21**	**$12**	**$9**	**($11)**	**($1)**	**$1**	**$3**	**$6**	**$8**	**$9**	**$9**	**$8**	**$10**
Cash Flow Statement	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total Working Capital Changes	(34)	13	(58)	(52)	(27)	(55)	119	(17)	(6)	41	(24)	(6)	(26)	9	(47)	5
Cash from Operations	**$6**	**($4)**	**$194**	**$351**	**$261**	**$0**	**$96**	**($27)**	**($1)**	**$69**	**$19**	**$63**	**$54**	**$84**	**$220**	**$353**
Capital expenditures	(38)	(43)	(313)	(259)	(195)	(45)	(25)	(12)	(8)	(91)	(57)	(58)	(56)	(55)	(226)	(162)
Cash from Investing	**($38)**	**($97)**	**($312)**	**($255)**	**($194)**	**($45)**	**($25)**	**($11)**	**($8)**	**($89)**	**($57)**	**($58)**	**($56)**	**($55)**	**($226)**	**($162)**
Increase (decrease) in Debt	21	(4)	162	(119)	(2)	(3)	(3)	(2)	0	(8)	0	0	0	0	0	0
Cash from Financing	**$21**	**$112**	**$136**	**($9)**	**($57)**	**($11)**	**($4)**	**($2)**	**$0**	**($17)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$0**	**$11**	**$16**	**$103**	**$113**	**$57**	**$125**	**$85**	**$76**	**$76**	**$37**	**$43**	**$41**	**$70**	**$70**	**$261**
Balance Sheet	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Property, Plant, & Equip. (net)	190	272	495	627	652	643	613	583	993	993	986	979	966	951	951	815
Total Assets	**$297**	**$446**	**$852**	**$1,117**	**$1,283**	**$1,299**	**$1,051**	**$1,059**	**$1,473**	**$1,473**	**$1,615**	**$1,642**	**$1,645**	**$1,634**	**$1,634**	**$1,711**
Long-term Debt, Net of Current	87	104	196	106	106	106	106	106	106	106	106	106	106	106	106	106
Stockholder Equity	134	230	393	741	781	781	720	676	1,083	1,083	1,122	1,126	1,138	1,142	1,142	1,192
Cash Flow Metrics	#	#	#	#	#	#	#	#	#	#	#	#	#	#	#	#
Free Cash Flow	**($32)**	**($47)**	**($119)**	**$92**	**$66**	**($45)**	**$71**	**($39)**	**($9)**	**($22)**	**($38)**	**$5**	**($2)**	**$29**	**($6)**	**$191**
FCF/share (diluted)	0.00	(0.68)	(1.73)	0.78	0.63	(0.39)	0.86	(0.46)	(0.11)	(0.24)	(0.26)	0.03	(0.01)	0.19	(0.04)	1.28
Operating Free Cash Flow	**$0**	**($170)**	**($184)**	**$171**	**$55**	**($88)**	**$162**	**($40)**	**($7)**	**$28**	**($99)**	**$2**	**($4)**	**$32**	**($68)**	**$189**
Balance Sheet Metrics	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Book Value (per share)	-	$3	$6	$6	$7	$7	$9	$8	$13	$12	$8	$8	$8	$8	$8	$8
Net Debt	**$110**	**$92**	**$180**	**$3**	**($7)**	**$49**	**($19)**	**$21**	**$30**	**$30**	**$68**	**$63**	**$65**	**$36**	**$36**	**($155)**
Total Debt/Capital	45.1%	31.1%	33.3%	12.5%	11.9%	11.9%	12.8%	13.5%	8.9%	8.9%	8.6%	8.6%	8.5%	8.5%	8.5%	8.1%
Net Debt/Capital	31.1%	22.3%	23.9%	0.4%	(0.9%)	5.6%	(2.8%)	2.9%	2.6%	2.6%	5.4%	5.0%	5.1%	2.9%	2.9%	(17.6%)
Return on equity	(5.9%)	(29.8%)	57.9%	44.4%	10.7%	2.2%	(35.3%)	(24.7%)	(18.9%)	(15.7%)	(7.4%)	1.3%	4.2%	1.6%	(0.0%)	4.3%
Return on capital (Net Debt)	**11.9%**	**(16.9%)**	**43.0%**	**40.5%**	**12.3%**	**3.6%**	**(33.0%)**	**(22.9%)**	**(17.0%)**	**(14.2%)**	**(6.4%)**	**1.9%**	**4.7%**	**2.2%**	**0.7%**	**5.5%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

MRC Global (MRC)

The Year Ahead for MRC

We continue to favor MRC's defensive characteristics as we head into 2021, and think the company is poised to benefit from an accretive product mix, self-help cost reduction measures, and an outsized exposure to gas utilities customers (36% of 3Q20 sales) that is differentiated among OFS peers. We believe Gas Utilities sales and Upstream's leverage to the recovering NAM completions market will be the primary drivers for higher top line off the 2020 exit rate next year. Meanwhile, we expect growth to be more limited in Downstream, particularly in Midstream Pipeline since its sales tend to lag D&C activity and line pipe pricing has yet to find a firm bottom. On net we expect MRC's 2021 top line result to be flat-to-down y/y (JPMe -2% y/y). Gross margin looks fairly stable going into 2021, coming off of resilient results YTD and a continued push to increase the mix of higher-margin valves sales. We are impressed by MRC's cost-out efforts in 2020, which should aid the company next year with SG&A guided to average $100mm/qtr or less (down from ~$133mm/qtr in 2019). MRC delivered on its countercyclical cash generation ability during the downturn, but with working capital benefits abating, we expect more modest FCF in 2021 (JPMe +$30mm).

Things to Focus On in 2021

- **Upstream and Gas Utilities top line growth to help offset weaker outlook for Midstream Pipeline and Downstream sales.** We see Upstream as providing the most support for higher volumes early in 2021 as the segment benefits from the recovery in U.S. onshore demand. However we anticipate that Upstream's sales will lag the broader drilling and completions rebound since many customers can rely on existing storage and infrastructure next year. We see good (if more modest) growth prospects in Gas Utilities as well, particularly as MRC's recent contract win with CenterPoint ramps up during the year. In Downstream we anticipate only mild top line growth in 2021 as more turnaround spending delayed from 2020 returns, likely most of all in 2Q21. MRC's Midstream Pipeline business looks most challenged to us as major projects started in early-2020 wind down and line pipe pricing remains quite weak.

- **Product mix to keep gross margin >19%.** MRC has recently delivered strong margin results, keeping GM% in the upper-19% range throughout 2020 despite the collapse in activity thanks to deft customer and inventory management. Coming off this good baseline into 2021 and with a continued emphasis on orienting its product mix towards valves we believe the company can keep gross margins above 19% throughout 2021 as well. As of 3Q20, 41% of MRC's TTM sales were from valves, and the company set a target to raise this to 45% by 2023.

- **FCF to remain positive in 2021, but countercyclical cash generation has mostly run its course:** MRC has done a good job in 2020 of demonstrating its countercyclical cash generation capability, producing $178mm CFO YTD and guiding to $220mm for FY2020. In 2021, we think most of the working capital liquidation benefit will be exhausted however, limiting our outlook for FCF (JPMe +$30mm). Given this view, we think MRC will be able to bring net debt under $300mm in 4Q20 and continue to slowly work down its debt balance next year. We believe MRC can meet its WC/TTM sales bogey of 19.5-19.9% in 2020, but this metric likely edges higher in 2021 (JPMe 20-21%).

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 27: MRC Global Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
Upstream	$1,729	$884	$1,049	$1,286	$1,107	$222	$134	$118	$114	$588	$135	$149	$156	$153	$593	$633
Midstream	1,485	1,165	1,603	1,677	1,450	321	292	282	265	1,160	276	291	302	302	1,172	1,229
Downstream	1,315	992	994	1,209	1,105	251	176	185	170	782	174	181	179	172	704	698
Total Revenue	**$4,529**	**$3,041**	**$3,646**	**$4,172**	**$3,662**	**$794**	**$602**	**$585**	**$550**	**$2,531**	**$585**	**$620**	**$637**	**$626**	**$2,469**	**$2,560**
COGS	(3743)	(2533)	(3064)	(3483)	(3009)	(646)	(523)	(471)	(449)	(2089)	(477)	(505)	(518)	(510)	(2010)	(2080)
Adjusted Gross Margins	18.0%	18.5%	18.7%	19.6%	19.5%	19.8%	19.6%	19.7%	19.5%	19.6%	19.3%	19.4%	19.5%	19.5%	19.4%	19.6%
SG&A	(601)	(504)	(522)	(558)	(531)	(126)	(104)	(97)	(94)	(421)	(97)	(97)	(97)	(97)	(387)	(383)
Total Costs & Expenses	(4344)	(3037)	(3586)	(4041)	(3540)	(772)	(627)	(568)	(543)	(2510)	(574)	(602)	(615)	(606)	(2398)	(2464)
Total D&A	(81)	(69)	(67)	(68)	(63)	(12)	(11)	(12)	(11)	(46)	(11)	(11)	(11)	(11)	(43)	(44)
EBITDA (Adjusted)	**$234**	**$71**	**$179**	**$280**	**$201**	**$34**	**$17**	**$24**	**$15**	**$90**	**$18**	**$25**	**$30**	**$28**	**$100**	**$126**
EBITDA (Adjusted) Margins	5.2%	2.3%	4.9%	6.7%	5.5%	4.3%	2.8%	4.1%	2.7%	3.6%	3.0%	4.1%	4.6%	4.4%	4.1%	4.9%
Total Operating Income Companywide	**$185**	**$4**	**$60**	**$135**	**$138**	**$22**	**$8**	**$11**	**$9**	**$50**	**$13**	**$20**	**$24**	**$22**	**$79**	**$104**
Total Operating Margins	4.1%	0.1%	1.6%	3.2%	3.8%	2.8%	1.3%	1.9%	1.7%	2.0%	2.1%	3.2%	3.8%	3.5%	3.2%	4.1%
Income Taxes	(57)	(1)	(8)	(22)	(24)	(5)	(1)	(7)	(1)	(14)	(2)	(3)	(4)	(4)	(13)	(18)
Tax Rate	*41%*	*-3%*	*28%*	*22%*	*24%*	*36%*	*-100%*	*140%*	*25%*	*65%*	*23%*	*23%*	*23%*	*23%*	*23%*	*22%*
Net Income	**($352)**	**($107)**	**$20**	**$50**	**$30**	**$3**	**($287)**	**($3)**	**($4)**	**($291)**	**($0)**	**$5**	**$9**	**$7**	**$20**	**$41**
Diluted Shares (Avg)	102	97	95	91	84	82	82	82	82	82	82	82	82	82	82	82
EPS (Adjusted, diluted)	**$0.75**	**($0.58)**	**$0.01**	**$0.58**	**$0.43**	**$0.04**	**($0.10)**	**($0.10)**	**($0.04)**	**($0.20)**	**($0.00)**	**$0.06**	**$0.10**	**$0.08**	**$0.25**	**$0.50**
Dividend per Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	586	231	(162)	(231)	118	9	39	89	51	188	(6)	3	(3)	4	(2)	7
Cash from Operations	**$690**	**$253**	**($48)**	**($11)**	**$242**	**$37**	**$47**	**$94**	**$60**	**$238**	**$5**	**$20**	**$18**	**$22**	**$66**	**$97**
Capital expenditures	(39)	(33)	(30)	(20)	(18)	(2)	(3)	(3)	(3)	(11)	(3)	(3)	(3)	(3)	(12)	(12)
Cash from Investing	**($41)**	**$16**	**($27)**	**($14)**	**($16)**	**($2)**	**($3)**	**($2)**	**$25**	**$18**	**($3)**	**($3)**	**($3)**	**($3)**	**($12)**	**($12)**
Cash from Financing	**($599)**	**($226)**	**$9**	**$24**	**($238)**	**($36)**	**($54)**	**($72)**	**($50)**	**($212)**	**($6)**	**($6)**	**($6)**	**($6)**	**($24)**	**($24)**
Cash at End of Period	**$69**	**$109**	**$48**	**$43**	**$32**	**$28**	**$19**	**$40**	**$75**	**$75**	**$72**	**$83**	**$92**	**$106**	**$106**	**$167**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	127	135	147	140	138	131	131	128	99	99	98	97	96	95	95	90
Total Assets	**$2,502**	**$2,164**	**$2,340**	**$2,434**	**$2,325**	**$2,301**	**$1,877**	**$1,805**	**$1,735**	**$1,735**	**$1,744**	**$1,771**	**$1,780**	**$1,784**	**$1,784**	**$1,835**
Long-term Debt, Net of Current	516	406	522	680	547	517	470	405	361	361	361	361	361	361	361	361
Stockholder Equity	955	763	759	692	642	617	341	347	346	346	348	355	366	375	375	424
Cash Flow Metrics																
Free Cash Flow	**$641**	**$196**	**($102)**	**($55)**	**$200**	**$29**	**$38**	**$85**	**$51**	**$203**	**($3)**	**$11**	**$9**	**$13**	**$30**	**$61**
FCF/share (diluted)	6	2	(1)	(1)	2	0	0	1	1	2	(0)	0	0	0	0	1
Operating Free Cash Flow	**$698**	**$298**	**($145)**	**($63)**	**$207**	**$47**	**$71**	**$79**	**$55**	**$252**	**($1)**	**$17**	**$11**	**$17**	**$43**	**$77**
Balance Sheet Metrics																
Book Value (per share)	$9	$8	$8	$8	$8	$7	$4	$4	$4	$4	$4	$4	$4	$5	$5	$5
Net Debt	**$455**	**$305**	**$478**	**$641**	**$519**	**$493**	**$455**	**$369**	**$289**	**$289**	**$293**	**$281**	**$272**	**$259**	**$259**	**$198**
Total Debt/Capital	35.4%	35.2%	40.9%	49.7%	46.2%	45.8%	58.2%	54.1%	51.3%	51.3%	51.2%	50.7%	49.9%	49.3%	49.3%	46.2%
Net Debt/Capital	32.3%	28.6%	38.6%	48.1%	44.7%	44.4%	57.2%	51.5%	45.5%	45.5%	45.7%	44.2%	42.7%	40.9%	40.9%	31.8%
Return on equity	5.9%	(6.5%)	(0.4%)	7.3%	7.9%	1.9%	(6.7%)	(9.3%)	(4.1%)	(3.4%)	(0.5%)	5.9%	9.5%	7.5%	5.6%	10.3%
Return on capital (Net Debt)	**3.3%**	**(4.5%)**	**(0.3%)**	**4.1%**	**4.3%**	**1.1%**	**(3.4%)**	**(4.2%)**	**(2.1%)**	**(1.8%)**	**(0.3%)**	**3.3%**	**5.3%**	**4.4%**	**3.2%**	**6.5%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Nabors Industries (NBR)

The Year Ahead for NBR

Nabors remains a challenging stock for many equity investors to own, as balance sheet concerns largely drive the narrative, and we think investor aversion has contributed to the shares' underperformance YTD (NBR -51% v. OSX -41%, HP/PTEN -45%/-46%). Underlying operational performance has been mixed for NBR in 2020, with U.S. rig activity and margins proving relatively resilient, but international margins continuing to slip lower. Heading into 2021, we expect Nabors to hold its L-48 market share in the high-teens, bolstered by strong relationships with the majors and large E&Ps, though margins should deteriorate as more spot-based contracts are added to the mix. Internationally NBR's activity prospects are looking brighter after the company provided line of sight to 14 rigs redeploying over the course of 2021. That said, we remain skeptical that the international, multi-continent business can generate cash through-cycle. Nabors has a fair amount of balance sheet (duration) optionality, and has recently engaged in liquidity management measures to buy time to a better market. However that still leaves the company's (diminished) market capitalization at risk. After the strong run off the October low, we think the setup is risked to the downside for 2021.

Things to Focus On in 2021

- **U.S. market share and margin defense.** Nabors' strong relationships with the majors and largest E&Ps helped add relative stability to its rig count in 2020, with NBR's active rigs falling 'only' -46% from 1Q20 to 3Q20 (v. -68% for the BKR L-48 rig count). Near-term we think NBR is likely to be returning more idle-but-contracted (IBC) rigs to work than securing incremental contracts. However in 2021 we expect the company to roughly keep pace with the rate of change of the broad L-48 rig count and maintain its high-teens market share. We expect these additional contracts to be dilutive to margins however, leading us to model day margins falling from ~$9.5k/d in 3Q20 to ~$6k/d by 4Q21.

- **International demand recovery and prospects for margin improvement.** Near-term international results are guided to be challenged as additional rigs come offline in 4Q20 and COVID-19 disruptions add costs. However, heading into 2021 we expect to see an inflection higher in both international activity and margins, led by the reactivation of ten rigs in MENA scheduled for 1H21. With this improved operating base, we model international day margins expanding to $13-14k/d in 2021, but see significant improvement beyond that level as unlikely given the mix away from the highest-margin rigs relative to last cycle. As such, we remain cautious on the international business's ability to materially change the FCF narrative for NBR in the near-to-medium term.

- **Delivering on FCF guidance and balance sheet optionality from exchange offer.** NBR indicated it can generate positive FCF, but set expectations for "double digits" (in $ millions), a fairly low bar considering the debt overhang. For our part, we think meaningful cash generation will be a challenge even with improved international activity, leading us to model at the low-end of NBR's range. The company launched a debt exchange offer in 4Q20 which should help extend a good portion of its near-term bond maturities (see here for detailed thoughts from our Energy High Yield colleagues). The exchange is part of what we view as prudent balance sheet management on Nabors' part, but it still leaves us skeptical of the company's ability to manage its debt load on full-cycle basis.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 28: Nabors Industries Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
United States Drilling	$1,257	$554	$805	$1,083	$1,241	$275	$174	$130	$153	$732	$160	$173	$183	$186	$702	$822
Canada Drilling	137	51	83	105	68	26	4	11	13	53	13	5	10	9	36	38
International Drilling	1,868	1,509	1,474	1,469	1,324	337	301	248	223	1,109	247	280	291	299	1,116	1,359
Rig Services	391	152	252	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Revenue	(150)	(102)	(173)	(121)	(103)	(17)	(11)	(9)	(17)	(54)	(19)	(20)	(22)	(22)	(83)	(99)
Total Revenue	**$3,871**	**$2,228**	**$2,564**	**$3,058**	**$3,043**	**$718**	**$534**	**$438**	**$435**	**$2,126**	**$474**	**$517**	**$547**	**$559**	**$2,097**	**$2,514**
COGS	(2371)	(1344)	(1718)	(1977)	(1929)	(462)	(327)	(270)	(284)	(1343)	(310)	(344)	(359)	(389)	(1403)	(1669)
SG&A	(366)	(261)	(302)	(322)	(309)	(69)	(54)	(54)	(49)	(225)	(51)	(53)	(60)	(38)	(203)	(218)
Total Costs & Expenses	(2737)	(1606)	(2020)	(2299)	(2238)	(531)	(380)	(324)	(333)	(1568)	(361)	(396)	(420)	(428)	(1605)	(1887)
Total D&A	(970)	(872)	(843)	(867)	(876)	(227)	(211)	(207)	(210)	(855)	(209)	(210)	(211)	(211)	(841)	(852)
EBITDA	**$1,134**	**$622**	**$544**	**$759**	**$805**	**$188**	**$154**	**$114**	**$102**	**$558**	**$112**	**$121**	**$128**	**$131**	**$491**	**$627**
Total Operating Income Companywide	**$163**	**($249)**	**($299)**	**($108)**	**($71)**	**($39)**	**($57)**	**($93)**	**($108)**	**($297)**	**($97)**	**($89)**	**($83)**	**($80)**	**($349)**	**($225)**
Total Operating Margins	4%	-11%	-12%	-4%	-2%	-5%	-11%	-21%	-25%	-14%	-20%	-17%	-15%	-14%	-17%	-9%
Income Taxes	27	117	74	6	(122)	(18)	(8)	3	(18)	(40)	29	28	26	26	109	85
Tax Rate	*27%*	*25%*	*14%*	*2%*	*-37%*	*-22%*	*-11%*	*2%*	*-11%*	*-9%*	*20%*	*20%*	*20%*	*20%*	*20%*	*20%*
Net Income	**($365)**	**($1,030)**	**($543)**	**($663)**	**($720)**	**($395)**	**($152)**	**($161)**	**($181)**	**($890)**	**($121)**	**($115)**	**($110)**	**($108)**	**($453)**	**($352)**
Diluted Shares (Avg)	6	6	6	7	7	7	7	7	7	7	7	7	7	7	7	7
EPS (Adjusted, diluted)	**($11.37)**	**($64.87)**	**($80.90)**	**($60.10)**	**($70.13)**	**($16.87)**	**($13.85)**	**($22.20)**	**($25.67)**	**($78.58)**	**($17.14)**	**($16.22)**	**($15.52)**	**($15.23)**	**($64.10)**	**($49.85)**
Dividend per Share	$12.00	$12.00	$12.00	$12.00	$4.50	$0.50	$0.50	$0.00	$0.00	$1.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	(15)	92	(385)	(216)	137	(85)	49	(1)	142	104	(61)	(1)	5	14	(42)	(39)
Cash from Operations	**$857**	**$532**	**$63**	**$326**	**$685**	**$59**	**$143**	**$46**	**$140**	**$388**	**($3)**	**$64**	**$76**	**$88**	**$226**	**$341**
Capital expenditures	(867)	(395)	(574)	(459)	(428)	(59)	(47)	(46)	(46)	(200)	(47)	(49)	(50)	(48)	(194)	(206)
Cash from Investing	**($227)**	**($382)**	**($502)**	**($367)**	**($356)**	**($51)**	**($41)**	**($37)**	**($46)**	**($176)**	**($47)**	**($49)**	**($50)**	**($48)**	**($194)**	**($206)**
Increase (decrease) in Debt	(678)	(70)	626	(479)	(273)	61	(91)	18	(10)	(22)	0	0	0	0	0	0
Cash from Financing	**($850)**	**($138)**	**$512**	**$156**	**($332)**	**$38**	**($99)**	**$13**	**($14)**	**($62)**	**($4)**	**($4)**	**($4)**	**($4)**	**($15)**	**($15)**
Cash at End of Period	**$255**	**$264**	**$337**	**$446**	**$437**	**$481**	**$482**	**$503**	**$583**	**$583**	**$530**	**$542**	**$564**	**$600**	**$600**	**$720**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	7,028	6,268	6,110	5,468	4,931	4,597	4,396	4,225	4,062	4,062	3,899	3,738	3,578	3,415	3,415	2,769
Total Assets	**$9,538**	**$8,187**	**$8,402**	**$7,854**	**$6,761**	**$6,309**	**$5,982**	**$5,817**	**$5,580**	**$5,580**	**$5,420**	**$5,301**	**$5,171**	**$5,061**	**$5,061**	**$4,609**
Long-term Debt, Net of Current	3,655	3,578	4,028	3,586	3,333	3,388	3,276	3,290	3,280	3,280	3,280	3,280	3,280	3,280	3,280	3,280
Stockholder Equity	4,283	3,247	2,912	2,701	1,983	1,556	1,413	1,256	1,041	1,041	886	737	594	453	453	(34)
Cash Flow Metrics																
Free Cash Flow	**($11)**	**$136**	**($512)**	**($133)**	**$257**	**($0)**	**$95**	**($0)**	**$94**	**$188**	**($49)**	**$15**	**$26**	**$40**	**$32**	**$135**
FCF/share (diluted)	(1.85)	24.68	(91.16)	(19.62)	36.53	(0.04)	13.51	(0.03)	13.26	26.69	(6.97)	2.18	3.66	5.62	4.49	19.11
Operating Free Cash Flow	**($190)**	**($160)**	**($25)**	**$106**	**($144)**	**$53**	**$9**	**$19**	**($150)**	**($68)**	**$105**	**$52**	**$52**	**$51**	**$260**	**$344**
Balance Sheet Metrics																
Book Value (per share)	$756	$587	$519	$398	$282	$221	$200	$178	$147	$147	$125	$104	$84	$64	$64	($5)
Net Debt	**$3,387**	**$3,283**	**$3,663**	**$3,105**	**$2,881**	**$2,898**	**$2,782**	**$2,776**	**$2,687**	**$2,687**	**$2,740**	**$2,728**	**$2,706**	**$2,670**	**$2,670**	**$2,550**
Total Debt/Capital	46.1%	52.4%	58.0%	57.0%	62.7%	68.5%	69.9%	72.4%	75.9%	75.9%	78.7%	81.6%	84.7%	87.9%	87.9%	101.1%
Net Debt/Capital	44.2%	50.3%	55.7%	53.5%	59.2%	65.1%	66.3%	68.9%	72.1%	72.1%	75.6%	78.7%	82.0%	85.5%	85.5%	101.4%
Return on equity	(1.4%)	(9.5%)	(14.7%)	(14.5%)	(21.1%)	(26.9%)	(26.3%)	(47.0%)	(63.2%)	(36.7%)	(50.3%)	(56.5%)	(65.8%)	(82.2%)	(60.6%)	(168.3%)
Return on capital (Net Debt)	**0.8%**	**(3.1%)**	**(4.0%)**	**(3.0%)**	**(4.0%)**	**(4.5%)**	**(3.8%)**	**(10.3%)**	**(12.8%)**	**(7.6%)**	**(8.9%)**	**(8.5%)**	**(8.4%)**	**(8.6%)**	**(8.7%)**	**(7.0%)**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

National Energy Services Reunited (NESR)

The Year Ahead for NESR

NESR arguably has the most stable market exposure in our coverage, which was reflective in its coverage-leading share performance amid the global collapse in activity in 2020 (+7% v. OSX -41% YTD). While the Middle East and North African markets were not spared by any stretch with BKR-reported rig counts down 20-25% this year, NESR was able to *grow* top line +28% (primarily organically). NESR's market positioning improved through the pandemic, heavily benefitting from its local crew and content v. its larger, diversified competitors. We expect idiosyncratic growth to continue with slightly expanding margins while keeping a lid on capital intensity, thus we stick with our "growth plus cash" thesis. Meanwhile, the market is valuing the stock below NAM-focused service companies (~3.8x JPMe 2022 v. ~8x JPMe Smid Cap avg. and ~6x pressure pumper average). Some of this disconnect can be attributed to the stock's market cap size flying below investors' radar, especially when considering the illiquidity (30-day average daily volume of 180k shares v. 230k this time last year). Since the initial merger in 2017, the company has showcased its ability to broaden its geographic reach and scope of services in the MENA region (e.g., SAPESCO, now integrated and bidding for scope in 2021). NESR also secured another long-term contract earlier this year for +$1bn in Oman across several product lines. While an eventual recovery in the region's activity will add a boost, NESR is wasting no time in executing its localized and differentiated growth strategy v. peers.

Things to Focus On in 2021

- **Top line continues to diverge from MENA activity.** MENA activity dipped ~20% in 3Q but NESR was able to report revenue up +7% q/q, continuing to show its idiosyncratic growth story. NESR has been able to take market share through the pandemic with its localized footprint as competitors in some cases were unable to complete work. Even as rig counts find a bottom across the region, we still NESR's model top line growing 17% y/y (after +28% y/y in 2020), boosted by unconventional work in Saudi Arabia, SAPESCO now fully integrated and, with that, a continued (and growing) build out in Oman.
- **Margins remained resilient amidst pandemic disruptions, now set to trend (a bit) higher.** NESR did well in managing flat D&E margins y/y in 2020 (with no adjustments on account of COVID-19). We expect ~170bps of improvement in 2021 (to ~25%) while Production Services looks more flat at ~29%, held down by frac startups. We expect the 3rd and 4th fleets to be deployed mid-year with a 5th coming in 2022. NESR remains a top line plus FCF story; holding margins (especially at these levels) is differentiated in OFS.
- **Cash plus growth thesis continues to play out.** We are modeling 2020 FCF of $45mm, followed by $96mm/$134mm in 2021/2022 (yielding 13%/18%). With the out-years aided by lower capex (even if accompanied by meaningful WC builds) we continue to expect NESR to pursue M&A and capex-light partnerships (e.g., NEX), building on its successful track record. While it's quiet for the time being, we expect an uptick in talks on the other side of COVID-19.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 29: National Energy Services Reunited Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Drilling & Evaluation			160	175	253	66	64	70	71	272	74	81	87	91	333	392
Production Services			298	340	406	133	139	148	152	572	150	158	169	179	656	773
Total Revenue	**$428**	**$431**	**$458**	**$527**	**$658**	**$199**	**$203**	**$218**	**$223**	**$844**	**$225**	**$239**	**$256**	**$270**	**$990**	**$1,165**
COGS	0	(303)	(312)	(381)	(495)	(158)	(164)	(178)	(180)	(680)	(182)	(191)	(202)	(211)	(786)	(901)
SG&A	0	(47)	(56)	(61)	(60)	(19)	(17)	(17)	(18)	(71)	(18)	(19)	(20)	(22)	(79)	(93)
Total Costs & Expenses	**$0**	**($358)**	**($316)**	**($450)**	**($571)**	**($181)**	**($185)**	**($199)**	**($202)**	**($768)**	**($204)**	**($215)**	**($228)**	**($238)**	**($885)**	**($1,018)**
Total D&A	($54)	($46)	($62)	($61)	($93)	($31)	($32)	($34)	($35)	($133)	($36)	($37)	($38)	($39)	($151)	($167)
EBITDA																
Drilling & Evaluation				$44	$57	$15	$16	$16	$17	$64	$18	$20	$22	$24	$84	$106
Production Services				$114	$140	$41	$40	$43	$44	$168	$44	$46	$49	$52	$191	$232
EBITDA Companywide	**$137**	**$104**	**$142**	**$162**	**$186**	**$51**	**$52**	**$56**	**$56**	**$215**	**$57**	**$61**	**$67**	**$71**	**$256**	**$314**
Interest Expense		(9)	(11)	(19)	(17)	(5)	(4)	(4)	(4)	(16)	(4)	(4)	(4)	(4)	(15)	(15)
Other Income (expense)		2	5	6	3	(0)	(0)	0	1	0	1	1	1	1	3	4
Income Taxes		($8)	($12)	($14)	($12)	($3)	($3)	($4)	($3)	($12)	($3)	($4)	($5)	($5)	($17)	($25)
Tax Rate		*17%*	*16%*	*16%*	*16%*	*16%*	*19%*	*20%*	*18%*	*18%*	*18%*	*18%*	*18%*	*18%*	*18%*	*18%*
Net Income		**$46**	**$63**	**$75**	**$42**	**$11**	**$10**	**$12**	**$15**	**$48**	**$14**	**$17**	**$21**	**$24**	**$76**	**$112**
Diluted Shares (Avg)		89	89	86	87	87	88	90	90	89	90	90	90	90	90	90
EPS (Adjusted, Diluted)		**$0.51**	**$0.70**	**$0.87**	**$0.76**	**$0.15**	**$0.14**	**$0.16**	**$0.17**	**$0.61**	**$0.16**	**$0.19**	**$0.23**	**$0.26**	**$0.85**	**$1.25**
Dividend per Share			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes				(49)	(37)	(31)	(1)	(12)	3	(41)	(12)	(28)	(16)	(1)	(57)	(58)
Cash from Operations				**$73**	**$93**	**$10**	**$43**	**$33**	**$53**	**$139**	**$38**	**$27**	**$44**	**$61**	**$170**	**$221**
Capital Expenditures				($58)	($112)	($24)	($27)	($25)	($18)	($93)	($17)	($18)	($19)	($20)	($74)	($87)
Cash from Investing				**($108)**	**($111)**	**($24)**	**($22)**	**($40)**	**($18)**	**($104)**	**($17)**	**($18)**	**($19)**	**($20)**	**($74)**	**($87)**
Increase (decrease) in Debt				$98	$72	($5)	$16	($16)	$0	($4)	$0	$0	($10)	$0	($10)	$0
Cash from Financing				**$68**	**$67**	**($10)**	**$10**	**($23)**	**$0**	**($23)**	**$0**	**$0**	**($10)**	**$0**	**($10)**	**$0**
Cash at End of Period				**$25**	**$73**	**$49**	**$79**	**$50**	**$85**	**$85**	**$107**	**$116**	**$130**	**$171**	**$171**	**$305**
Balance Sheet ($ in millions)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Assets			**$620**	**$1,343**	**$1,515**	**$1,537**	**$1,665**	**$1,663**	**$1,674**	**$1,674**	**$1,687**	**$1,702**	**$1,715**	**$1,743**	**$1,743**	**$1,862**
Long-term Debt, Net of Current			**147**	**225**	**331**	**323**	**335**	**320**	**320**	**320**	**320**	**320**	**310**	**310**	**310**	**310**
Stockholder Equity			389	831	886	900	912	926	941	941	955	973	993	1,017	1,017	1,129
Cash Flow Metrics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Free Cash Flow				**$15**	**($19)**	**($14)**	**$16**	**$9**	**$35**	**$45**	**$21**	**$9**	**$24**	**$41**	**$96**	**$134**
FCF/share (diluted)				$0.18	($0.22)	($0.16)	$0.18	$0.10	$0.39	$0.51	$0.24	$0.10	$0.27	$0.46	$1.07	$1.49
FCF Yield				2%	-2%	-8%	9%	5%	19%	6%	12%	5%	14%	23%	13%	19%
Operating Free Cash Flow				**($8)**	**($17)**	**$38**	**$35**	**$30**	**$38**	**$141**	**$21**	**$8**	**$24**	**$40**	**$93**	**$129**
Balance Sheet Metrics	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Book Value (per share)				$9.67	$10.18	$10.31	$10.34	$10.30	$10.47	$10.59	$10.63	$10.82	$11.05	$11.32	$11.32	$12.56
Net Debt				**$277**	**$310**	**$336**	**$342**	**$349**	**$315**	**$315**	**$293**	**$284**	**$260**	**$219**	**$219**	**$85**
Total Debt/Capital				26.7%	30.2%	30.0%	31.6%	30.2%	29.8%	29.8%	29.5%	29.1%	28.2%	27.7%	27.7%	25.7%
Net Debt/Capital				20.0%	20.6%	21.4%	21.4%	21.5%	20.0%	20.0%	19.0%	18.4%	17.2%	15.0%	15.0%	6.5%
Return on equity				12.3%	7.7%	5.8%	5.3%	6.2%	6.4%	5.9%	6.1%	7.2%	8.5%	9.4%	7.8%	10.5%
Return on capital (Net Debt)				**11.2%**	**7.0%**	**5.5%**	**4.9%**	**5.4%**	**5.7%**	**5.5%**	**5.6%**	**6.5%**	**7.6%**	**8.5%**	**7.1%**	**10.2%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

National Oilwell Varco (NOV)

The Year Ahead for NOV

In the "cycle of abundance", National Oilwell Varco's disadvantaged position in the energy supply chain was exacerbated in 2020 with book:bill of only ~0.6x as the upstream ground to a halt by mid-year. Both the NAM onshore and global deepwater markets face challenges with limited scope for a rebound until the latter half of 2021 at the earliest, though NOV is finding some modest relief in renewables with more offshore wind support vessel kits. Even prior successes such as Aramco newbuilds are getting deprioritized as intense capital discipline snakes through the supply chain of even the most stable end markets. The company has been successful in adjusting its business accordingly with +$700mm in cost-out and prioritizing FCF ($567mm YTD), helped by $318mm in working capital unwinds which should continue at a lower level in 2021. We remind investors that while NOV's balance sheet isn't a concern, those of its OFS and E&P customers will remain an issue in the quarters to come. The stock's fall this year is relatively in-line with the OSX (down -44%) and Street consensus still looks too high in our view; we are 11%/15% below on 2021/2022 EBITDA (with the increasingly common "law of small numbers" caveat). With the recent run in the shares (+76% since 10/28 v. +77% OSX), a ~5% normalized FCF/EV yield looks fairly full to us, especially with the Street a little too constructive on progress in 2021.

Things to Focus On in 2021

- **Renewables providing a (modest) buffer at the trough while upstream equipment orders languish.** 3Q proved to be barren for Rig Tech with only $57mm in orders (-74% y/y) but 4Q could more than triple with the help of offshore wind (up to $70mm per kit). It's undoubtedly positive to see NOV's engineering prowess deployed across different emerging end markets but for the company ultimately needs an offshore recovery for its stock to reach it potential. Given our macro outlook and WTI looking range-bound in the $40s in 2021, we model a tepid recovery in orders. The aftermarket business is likely to remain weak but should benefit from considerably lower COVID-19 disruptions and rigs on standby. With ~17% lower revenue y/y, we expect EBITDA margins to hold better after the 2020 volatility (3% trough in 2Q20), improving ~50bps y/y to 7.2% in 2021.
- **CAPS orders to slowly crawl out of the trough with the margin path in focus.** We model a 20% increase (only +$34mm q/q) in 4Q orders ahead of NAM's ramp in frac activity and expect a recovery in orders to be subdued through 2021. With backlog drying up (now less than $800mm) we assume CAPS revenue declines -18% y/y (after -12% y/y in 2020). After 3Q margins held in relatively well, we think they will continue to deteriorate in 2021 on lower volumes (-140bps y/y).
- **Prepping for "lower for longer" while wringing the cash rag remains the prudent plan.** If the $700mm target was achieved earlier than expected, we expect NOV to continue to seek out incremental savings in the coming quarters. Working capital has been a ~$570mm source of cash in the last two quarters and we expect that to continue if at a slower clip in 2021 (~$200mm). Due to COVID-related delays on the Saudi facility, ~$50mm of capex will slip into 2021 while 2022 capex should revert to ~3% of sales (~$170mm). On net, our 2021/2022 FCF assumptions yield only ~4%, leaving valuation fairly full.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 30: National Oilwell Varco Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
Rig Technologies		3,110	2,252	2,575	2,682	557	476	449	458	1,940	399	382	408	426	1,615	1,912
Wellbore Technologies	3,718	2,199	2,577	3,235	3,214	691	442	361	371	1,865	384	401	421	442	1,649	1,856
Completion & Production	3,365	2,241	2,672	2,931	2,771	675	611	601	560	2,447	519	487	486	510	2,002	2,100
Eliminations	(1,805)	(299)	(197)	(288)	(188)	(40)	(33)	(27)	(27)	(127)	(27)	(28)	(29)	(31)	(115)	(130)
Total Revenue Companywide	**$14,757**	**$7,251**	**$7,304**	**$8,453**	**$8,479**	**$1,883**	**$1,496**	**$1,384**	**$1,361**	**$6,124**	**$1,276**	**$1,243**	**$1,285**	**$1,347**	**$5,150**	**$5,738**
Total D&A	($747)	($646)	($698)	($690)	($533)	($105)	($82)	($83)	($83)	($353)	($82)	($82)	($82)	($81)	($327)	($325)
EBITDA	**$2,381**	**$322**	**$611**	**$910**	**$885**	**$178**	**$84**	**$71**	**$65**	**$398**	**$62**	**$61**	**$67**	**$78**	**$268**	**$431**
EBITDA Margins	16.1%	4.4%	8.4%	10.8%	10.4%	9.5%	5.6%	5.1%	4.7%	6.5%	4.9%	4.9%	5.3%	5.8%	5.2%	7.5%
Total Operating Income Companywide	**$1,634**	**($324)**	**($87)**	**$220**	**$352**	**$73**	**$2**	**($12)**	**($18)**	**$45**	**($20)**	**($21)**	**($14)**	**($4)**	**($59)**	**$106**
Rig Technologies Margins	0%	7%	5%	9%	10%	6%	-1%	2%	3%	3%	2%	2%	3%	4%	3%	7%
Wellbore Technologies Margins	5%	-13%	-3%	5%	8%	8%	-1%	-7%	-5%	0%	-4%	-4%	-3%	-2%	-3%	-1%
Completion & Production Margins	9%	0%	5%	6%	4%	6%	9%	8%	5%	7%	6%	6%	6%	6%	6%	8%
Total Operating Margins	**11%**	**-4%**	**-1%**	**3%**	**4%**	**4%**	**0%**	**-1%**	**-1%**	**1%**	**-2%**	**-2%**	**-1%**	**0%**	**-1%**	**2%**
Income Taxes	($437)	$200	$40	($63)	($88)	($12)	$27	$49	$12	$75	$15	$15	$13	$10	$54	$4
Tax Rate	*29%*	*43%*	*21%*	*126%*	*52%*	*32%*	*83%*	*93%*	*20%*	*71%*	*30%*	*30%*	*30%*	*30%*	*30%*	*30%*
Net Income	**($768)**	**($1,129)**	**($179)**	**($32)**	**($6,095)**	**($2,047)**	**($93)**	**($55)**	**($49)**	**($2,244)**	**($37)**	**($38)**	**($33)**	**($26)**	**($134)**	**($18)**
Diluted Shares (Avg)	388	376	377	381	382	383	385	385	385	385	385	385	385	385	385	385
EPS (Adjusted, diluted)	**$2.75**	**($0.70)**	**($0.41)**	**($0.06)**	**$0.21**	**$0.07**	**($0.03)**	**($0.01)**	**($0.13)**	**($0.10)**	**($0.10)**	**($0.10)**	**($0.09)**	**($0.07)**	**($0.35)**	**($0.05)**
Dividend per Share	$1.84	$0.61	$0.20	$0.20	$0.20	$0.05	$0.00	$0.00	$0.00	$0.05	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Additional Information																
Rig Systems Details ($ in millions)																
Orders Rig	1,005	463	495	2,497	1,013	146	74	57	218	495	84	90	104	123	401	600
Backlog Rig	6,080	2,488	1,888	3,117	3,000	2,930	2,790	2,660	2,679	2,679	2,583	2,503	2,429	2,364	2,364	2,115
Book-to-Bill	0.2x	0.2x	0.5x	2.3x	0.9x	0.7x	0.3x	0.3x	1.1x	0.6x	0.5x	0.5x	0.6x	0.7x	0.6x	0.7x
Revenue from Backlog	6,106	1,898	998	1,088	1,136	208	219	199	199	825	179	170	179	188	715	849
C&P Details ($ in millions)																
Orders	1,330	1,151	1,788	1,564	2,055	335	196	169	203	903	197	207	217	228	848	1,006
Backlog	969	818	1,066	894	1,300	1,190	1,000	789	702	702	618	549	477	451	451	291
Book-to-Bill	0.6x	0.9x	1.2x	0.9x	1.3x	0.8x	0.5x	0.4x	0.7x	0.6x	0.7x	0.8x	0.8x	0.9x	0.8x	0.9x
Revenue from Backlog Completion &	2,061	1,340	1,541	1,697	1,625	416	388	394	290	1,488	281	275	289	253	1,099	1,166
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	(466)	676	455	(86)	35	(249)	326	241	192	510	105	111	27	(33)	211	54
Cash from Operations	**$1,332**	**$932**	**$832**	**$521**	**$714**	**$39**	**$378**	**$323**	**$226**	**$966**	**$150**	**$155**	**$76**	**$23**	**$404**	**$362**
Capital expenditures	($453)	($281)	($192)	($244)	($233)	($68)	($56)	($49)	($67)	($240)	($57)	($53)	($46)	($43)	($200)	($172)
Cash from Investing	**($514)**	**($341)**	**($249)**	**($457)**	**($315)**	**($53)**	**($58)**	**($49)**	**($67)**	**($227)**	**($57)**	**($53)**	**($46)**	**($43)**	**($200)**	**($172)**
Increase (decrease) in LT Debt	$762	($897)	($504)	($8)	($489)	$0	$0	($181)	$0	($181)	$0	$0	$0	$0	$0	$0
Cash from Financing	**($2,163)**	**($1,126)**	**($571)**	**($27)**	**($647)**	**($43)**	**$16**	**($229)**	**$0**	**($256)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$2,080**	**$1,408**	**$1,437**	**$1,427**	**$1,171**	**$1,115**	**$1,447**	**$1,485**	**$1,644**	**$1,644**	**$1,737**	**$1,839**	**$1,868**	**$1,848**	**$1,848**	**$2,038**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	3,124	3,150	3,002	2,797	2,354	2,003	2,010	1,994	1,978	1,978	1,953	1,925	1,889	1,851	1,851	1,698
Total Assets	**$26,725**	**$21,140**	**$20,206**	**$19,796**	**$13,149**	**$10,690**	**$10,447**	**$10,168**	**$10,070**	**$10,070**	**$9,985**	**$9,921**	**$9,883**	**$9,866**	**$9,866**	**$9,873**
Long-term Debt, Net of Current	**$3,928**	**$2,708**	**$2,706**	**$2,704**	**$1,989**	**$2,002**	**$2,029**	**$1,824**	**$1,824**	**$1,824**	**$1,824**	**$1,824**	**$1,824**	**$1,824**	**$1,824**	**$1,824**
Stockholder Equity	$16,460	$14,003	$14,160	$13,889	$7,846	$5,554	$5,533	$5,540	$5,491	$5,491	$5,454	$5,416	$5,383	$5,357	$5,357	$5,339
Cash Flow Metrics																
Free Cash Flow	**$879**	**$651**	**$640**	**$277**	**$481**	**($29)**	**$322**	**$274**	**$159**	**$726**	**$93**	**$102**	**$30**	**($20)**	**$204**	**$190**
FCF/share (diluted)	$2.26	$1.73	$1.70	$0.73	$1.26	($0.08)	$0.84	$0.71	$0.41	$1.89	$0.24	$0.26	$0.08	($0.05)	$0.53	$0.49
Operating Free Cash Flow	**$2,915**	**$2,123**	**$843**	**$653**	**$1,492**	**$164**	**$407**	**$274**	**$174**	**$1,018**	**$95**	**$106**	**$34**	**($13)**	**$223**	**$216**
Balance Sheet Metrics																
Book Value (per share)	$42	$37	$38	$36	$21	$15	$14	$14	$14	$14	$14	$14	$14	$14	$14	$14
Net Debt	**$1,850**	**$1,806**	**$1,275**	**$1,284**	**$818**	**$887**	**$582**	**$339**	**$180**	**$180**	**$87**	**($15)**	**($44)**	**($24)**	**($24)**	**($214)**
Total Debt/Capital	19.3%	18.7%	16.1%	16.3%	20.2%	26.5%	26.8%	24.8%	24.9%	24.9%	25.1%	25.2%	25.3%	25.4%	25.4%	25.5%
Net Debt/Capital	10.1%	11.4%	8.3%	8.5%	9.4%	13.8%	9.5%	5.8%	3.2%	3.2%	1.6%	(0.3%)	(0.8%)	(0.5%)	(0.5%)	(4.2%)
Return on equity	5.8%	(1.8%)	(1.1%)	(0.1%)	0.7%	1.5%	(0.4%)	(0.2%)	(3.4%)	(0.4%)	(2.6%)	(2.6%)	(2.3%)	(1.8%)	(2.3%)	(0.2%)
Return on capital (Net Debt)	**5.9%**	**(1.3%)**	**(0.6%)**	**(0.2%)**	**1.0%**	**2.0%**	**(0.1%)**	**(0.1%)**	**(2.2%)**	**(0.1%)**	**(1.5%)**	**(1.6%)**	**(1.3%)**	**(0.7%)**	**(1.3%)**	**0.9%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

NexTier Oilfield Solutions (NEX)

The Year Ahead for NEX

NEX started 2020 fresh off the completion of the merger of FRAC+CJ, making it the second-largest NAM frac provider (though LBRT is set to surpass it upon the closing of the OneStim deal). The company had ambitious cost-savings initiatives underway in 1Q20 as part of the merger, and the downturn only accelerated those efforts, meaning NexTier will enter 2021 with a cost base akin to the Keane-only level from 2018 (~$80mm annual SG&A). We think NEX fits solidly within the frac "haves" camp and we expect the company to maintain high utilization levels relative to lower-quality peers as E&Ps (particularly the larger ones with long ties to NEX) seek out high-efficiency crews and ESG-friendly dual-fuel fleets. However, the stock continues to overlook NEX's advantaged position, in our view, with the shares trading at only ~0.3x replacement value (v. ~0.5x for LBRT and PUMP). Though material cash generation may be unlikely in 2021, we like NEX's strong balance sheet, experienced management team, and technological leadership that make it solid competitor in the NAM frac market.

Things to Focus On in 2021

- **Extent of frac demand recovery in 1Q21 sets the tone for 2021.** In our macro forecast, we anticipate that E&Ps will need to ramp up completions activity materially in 1H21 in order to meet broad guidance for 2021 annual production to hold flat relative to 4Q20. This represents a critical point for NexTier to demonstrate that its fleets are as in-demand as those of other high-quality frac providers. For our part, we think NEX can stay at the high-end of its 8-12% market share bogey in 2021, implying an active fleet count of ~20 by mid-2021. After this point though, we anticipate E&Ps will largely be running at maintenance activity levels, and expect the fleet count to trend only moderately higher in 2H21.

- **Developments on an e-frac solution, hopefully accompanied by customer contracts.** NexTier will be trialing the NOV Ideal eFrac fleet in 1Q21, adding one of the eFrac prototype pumps to an existing fleet to conduct tests. The trial is set to last 2-3 months, after which NEX can decide if it will order an entire fleet of electric equipment (~$40mm without a power source). We suspect NEX is likely to move forward with ordering a e-frac fleet in 2021, but is very conscious of investors' (justified) skepticism regarding OFS spending on e-frac in today's capital-constrained environment. NexTier can likely assuage some of these concerns by securing strong contracts for any newbuild e-frac equipment, perhaps akin to the model of super-spec rig newbuilds last cycle.

- **FCF generation looks challenged for 1H21, but better in 2H21.** We model NEX burning cash through 1H21 as maintenance capex normalizes and some working capital build is likely needed as activity ramps up early in the year. Annualized maintenance capex is guided to remain in the $3-3.5mm/fleet range going forward, and we assume an average of ~$10mm/qtr of growth spending primarily targeting technology initiatives. We think these investments serve to differentiate NexTier's fleet and likely come with fairly quick paybacks, leaving a more constructive cash generation setup in 2H21/2022. An e-frac investment could potentially extend the timeframe to positive FCF for NEX, but we believe the company will be prudent in securing a contract for any such commitment.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 31: NexTier Oilfield Solutions Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Completions and Wireline	1,579	955	2,766	3,555	2,727	513	179	154	171	1,017	228	276	304	295	1,103	1,263
Well Construction and Intervention	0	0	0	376	270	57	17	10	18	102	23	28	31	30	112	128
Other Services	535	437	415	429	410	58	0	0	0	58	0	0	0	0	0	0
Total Revenue	**$2,114**	**$1,392**	**$3,181**	**$4,359**	**$3,406**	**$628**	**$196**	**$164**	**$189**	**$1,176**	**$251**	**$304**	**$334**	**$325**	**$1,214**	**$1,391**
Total COGS	(1811)	(1358)	(2555)	(3385)	(2712)	(512)	(164)	(149)	(167)	(993)	(220)	(255)	(274)	(266)	(1015)	(1105)
Total SG&A	(206)	(256)	(311)	(295)	(333)	(48)	(31)	(20)	(20)	(118)	(19)	(19)	(20)	(19)	(76)	(75)
Corporate and Other	(17)	111	31	2	88	(4)	(2)	7	0	1	0	0	0	0	0	0
Total Costs & Expenses	**($2,034)**	**($1,504)**	**($2,835)**	**($3,679)**	**($2,958)**	**($564)**	**($197)**	**($162)**	**($187)**	**($1,110)**	**($239)**	**($274)**	**($294)**	**($285)**	**($1,091)**	**($1,180)**
Total D&A	**($346)**	**($318)**	**($300)**	**($484)**	**($386)**	**($86)**	**($75)**	**($74)**	**($73)**	**($308)**	**($73)**	**($73)**	**($73)**	**($73)**	**($292)**	**($289)**
Total Gross Profit	**$303**	**$33**	**$626**	**$974**	**$694**	**$119**	**$32**	**$14**	**$21**	**$187**	**$31**	**$49**	**$61**	**$59**	**$199**	**$286**
Total Gross Margins	14.3%	2.4%	19.7%	22.3%	20.4%	19.0%	16.5%	8.8%	11.4%	15.9%	12.4%	16.1%	18.1%	18.0%	16.4%	20.5%
EBITDA																
Completions and Wireline	140	(7)	491	750	531	101	3	(3)	2	103	12	29	39	38	117	202
Well Construction and Intervention	0	0	0	68	28	9	(2)	(2)	(1)	5	1	2	2	2	6	9
Other Services	(33)	7	18	37	42	13	0	0	0	13	0	0	0	0	0	0
Corporate and Elimination	(26)	(93)	(163)	(181)	(143)	(50)	0	0	0	(50)	0	0	0	0	0	0
EBITDA Companywide	**$80**	**($92)**	**$345**	**$676**	**$465**	**$72**	**$2**	**($2)**	**$2**	**$73**	**$12**	**$30**	**$41**	**$40**	**$123**	**$211**
Total EBITDA Margin	3.8%	-6.6%	10.9%	15.5%	13.7%	11.5%	0.9%	-1.5%	0.9%	6.2%	4.9%	9.9%	12.1%	12.3%	10.1%	15.1%
Interest Expense	(106)	(193)	(29)	(37)	(22)	(6)	(5)	(6)	(5)	(22)	(5)	(5)	(5)	(5)	(19)	(16)
Other Income (expense)	7	(35)	5	2	(0)	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	$111	$118	$38	($2)	($2)	($0)	($0)	($1)	($2)	($3)	($1)	($1)	($1)	($1)	($4)	($3)
Tax Rate	*30%*	*19%*	*-182%*	*1%*	*-6%*	*-1%*	*-1%*	*-1%*	*-2%*	*-1%*	*-2%*	*-2%*	*-2%*	*-2%*	*-2%*	*-3%*
Net Income	**($942)**	**($1,113)**	**($11)**	**($71)**	**($210)**	**($72)**	**($112)**	**($102)**	**($78)**	**($365)**	**($67)**	**($49)**	**($38)**	**($39)**	**($193)**	**($97)**
Diluted Shares (Avg)	269	294	206	218	211	213	214	214	214	214	214	214	214	214	214	214
EPS (Adjusted, Diluted)	**($0.94)**	**($1.77)**	**$0.29**	**$0.71**	**($0.13)**	**($0.09)**	**($0.37)**	**($0.38)**	**($0.37)**	**($1.22)**	**($0.31)**	**($0.23)**	**($0.18)**	**($0.18)**	**($0.90)**	**($0.45)**
Dividend per Share	$0.00	$0.00	$0.00	$0.00	$0.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Additional Segment Information	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Average Revenue per Active Fleet (annualized)	69.1	39.8	71.2	85.6	76.6	71.2	71.9	71.9	71.1	71.5	71.1	71.9	71.1	70.4	71.1	70.4
EBITDA per Active Fleet (annualized)			26.1	19.4	16.6	14.9	1.2	(1.3)	0.7	6.7	2.8	5.7	7.0	6.9	10.3	17.9
Total Frac Fleets	8	20	24	48	49	45	45	37	37	45	37	37	37	37	45	45
Total Deployed Frac Fleets	5	10	34	42	39	29	13	13	16	23	20	25	25	25	16	16
% Frac Utilization	100%	100%	55%	91%	82%	60%	24%	30%	81%	67%	84%	81%	89%	88%	71%	71%
Cash Flow Statement ($ in millions)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total Working Capital Changes	142	145	(217)	55	102	3	94	(9)	(11)	78	3	(37)	(6)	3	(38)	2
Cash from Operations	**$141**	**($161)**	**$80**	**$692**	**$327**	**$48**	**$62**	**($28)**	**($12)**	**$71**	**$13**	**($9)**	**$33**	**$41**	**$78**	**$210**
Capital Expenditures	($192)	($81)	($352)	($589)	($321)	($41)	($43)	($13)	($29)	($125)	($25)	($27)	($29)	($29)	($110)	($119)
Cash from Investing	**($851)**	**($254)**	**($526)**	**($574)**	**($281)**	**$14**	**($36)**	**($3)**	**($24)**	**($49)**	**($25)**	**($27)**	**($29)**	**($29)**	**($110)**	**($119)**
Increase (decrease) in Debt	$733	$276	($5)	$63	($4)	$172	($174)	($1)	$0	($3)	$0	$0	$0	$0	$0	$0
Cash from Financing	**$724**	**$451**	**$428**	**($113)**	**($89)**	**$171**	**($177)**	**($1)**	**($0)**	**($8)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$79**	**$114**	**$210**	**$216**	**$255**	**$489**	**$337**	**$305**	**$269**	**$269**	**$257**	**$221**	**$225**	**$238**	**$238**	**$329**
Balance Sheet ($ in millions)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Total Assets	**$2,558**	**$1,899**	**$2,652**	**$2,479**	**$1,665**	**$1,787**	**$1,310**	**$1,211**	**$1,137**	**$1,137**	**$1,088**	**$1,042**	**$1,020**	**$980**	**$980**	**$894**
Long-term Debt, Net of Current	**1,353**	**267**	**279**	**344**	**335**	**335**	**334**	**334**	**334**	**334**	**334**	**334**	**334**	**334**	**334**	**334**
Stockholder Equity	713	(136)	1,835	1,641	887	818	712	614	544	544	481	437	402	368	368	287
Cash Flow Metrics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Free Cash Flow	**($52)**	**($242)**	**($272)**	**$104**	**$5**	**$8**	**$19**	**($41)**	**($41)**	**($55)**	**($12)**	**($36)**	**$4**	**$12**	**($32)**	**$91**
FCF/share (diluted)	$0.00	($0.82)	($1.32)	$0.48	$0.02	$0.04	$0.09	($0.19)	($0.19)	($0.26)	($0.06)	($0.17)	$0.02	$0.06	($0.15)	$0.43
Operating Free Cash Flow	**$36**	**($362)**	**($333)**	**$163**	**$194**	**$96**	**$87**	**($4)**	**($44)**	**$135**	**($9)**	**($31)**	**($1)**	**$9**	**($32)**	**$74**
Balance Sheet Metrics	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Book Value (per share)	$2.65	($0.46)	$8.89	$7.54	$4.21	$3.84	$3.33	$2.87	$2.54	$2.55	$2.25	$2.04	$1.88	$1.72	$1.72	$1.34
Net Debt	**$1,291**	**$156**	**$73**	**$135**	**$104**	**$23**	**$17**	**$48**	**$84**	**$84**	**$96**	**$132**	**$128**	**$116**	**$116**	**$24**
Total Debt/Capital	65.8%	202.2%	13.4%	17.6%	28.8%	38.5%	33.2%	36.5%	39.4%	39.4%	42.3%	44.7%	46.8%	49.0%	49.0%	55.2%
Net Debt/Capital	39.2%	88.7%	3.7%	7.1%	9.5%	2.6%	2.3%	6.8%	11.8%	11.8%	14.3%	18.9%	19.4%	19.3%	19.3%	7.3%
Return on equity	-30.8%	-180.6%	7.0%	8.9%	-2.2%	-9.4%	-41.5%	-49.5%	-54.1%	-36.3%	-52.3%	-42.6%	-36.3%	-40.1%	-42.2%	-29.7%
Return on capital (Net Debt)	**-10.4%**	**-35.9%**	**14.7%**	**10.4%**	**-0.3%**	**-6.1%**	**-37.8%**	**-44.0%**	**-45.2%**	**-29.3%**	**-41.2%**	**-30.6%**	**-24.1%**	**-26.6%**	**-31.1%**	**-20.3%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Nine Energy Services (NINE)

The Year Ahead for NINE

NINE has not been spared this year by the deterioration in NAM activity, with significant impact across all of its segments. With the transition to its desired asset-light business model still in-process, the main factors determining NINE's success in 2021 remain the commercialization of new technology and further de-risking of the balance sheet. Customers have begun to show acceptance of NINE's dissolvables in 2H20, and we view market penetration in 2021 a critical catalyst. Debt repurchases through the trough have been deft; however, we anticipate improvements in profitability will be needed for NINE to both continue this progress and earn credit from the equity market. We model revenue improving sequentially and a bit better than 2020 (JPMe +6% y/y), with EBITDA approaching breakeven (JPMe -$4mm).

Things to Focus On in 2021

- **New product commercialization remains a "show me" story.** As the biggest catalyst for NINE heading into 2020, the commercialization of the new dissolvable plug unfortunately coincided with the pandemic-led sharp decline in NAM activity. However, adoption in 2020 was still notable and the percentage of dissolvables sold in Nine's portfolio increased despite the market remaining geared towards composites. Poor Coiled Tubing pricing remains a headwind for revenue growth in dissolvables, and improvement is necessary for long-term growth despite management's confidence in medium-term operator adoption.
- **Expansion into the Haynesville should drive revenue growth.** While the more drilling-oriented Cementing did not benefit from the incremental pick-up in completions activity to the extent of NINE's other segments, organic expansion into the Haynesville Basin in 3Q should prove to be advantageous as the company aims to scale the segment. Cementing is one of the least saturated markets to compete in (as is the Haynesville), leaving NINE a more open path to expansion. While we anticipate limited growth near-term, we model segment revenue and top line improving each quarter in 2021 (JPMe -15% y/y). We expect meaningful contributions from Completion Tools and Coiled Tubing to come out of the expansion first (JPMe +60%/+55% e/e).
- **Solid execution on debt repurchases, but more self-help is needed.** NINE had notably positive execution on debt reduction in 2020, repurchasing ~$53mm of its senior notes for $14.6mm in cash YTD. Capital allocation remains encouraging, with NINE successfully reducing capex as it shifted to its asset-light business model (and a collapse in volumes). However, with debt still elevated at ~$347mm we think NINE is going to need help from top line and EBITDA expansion to further reduce the burden via positive free cash.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 32: Nine Energy Services Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Cementing Services	97	55	139	200	218	49	20	15	15	100	19	21	22	23	84	99
Wireline	132	81	138	245	236	45	10	13	15	83	18	20	22	24	84	92
Completion Tools	73	20	55	132	186	32	15	14	17	78	22	24	27	27	100	160
Coiled Tubing	78	66	133	167	135	21	8	7	9	45	13	14	15	14	55	51
Completion Solutions	380	221	466	745	775	147	53	50	56	305	71	79	86	87	323	402
Production Solutions	98	61	79	82	58	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	**$479**	**$282**	**$544**	**$827**	**$833**	**$147**	**$53**	**$50**	**$56**	**$305**	**$71**	**$79**	**$86**	**$87**	**$323**	**$402**
COGS	(373)	(246)	(448)	(632)	(670)	(126)	(57)	(52)	(54)	(289)	(66)	(71)	(74)	(75)	(286)	(332)
SG&A	(43)	(39)	(41)	(74)	(81)	(16)	(11)	(11)	(8)	(47)	(9)	(10)	(10)	(10)	(40)	(50)
Total Costs & Expenses (ex Other)	**($416)**	**($285)**	**($489)**	**($706)**	**($751)**	**($142)**	**($68)**	**($63)**	**($62)**	**($336)**	**($75)**	**($81)**	**($85)**	**($86)**	**($327)**	**($382)**
Total D&A	**($68)**	**($64)**	**($62)**	**($64)**	**($69)**	**($13)**	**($13)**	**($12)**	**($12)**	**($49)**	**($12)**	**($12)**	**($12)**	**($12)**	**($49)**	**($52)**
Total Gross Profit	**$105**	**$36**	**$95**	**$196**	**$170**	**$21**	**($4)**	**($3)**	**$0**	**$14**	**$2**	**$5**	**$8**	**$8**	**$23**	**$52**
Total Gross Margins	**22.0%**	**12.8%**	**17.5%**	**23.6%**	**20.5%**	**14.1%**	**-7.5%**	**-6.0%**	**0.7%**	**4.6%**	**2.6%**	**6.4%**	**9.0%**	**9.4%**	**7.1%**	**13.0%**
EBITDA Companywide	**$74**	**$10**	**$56**	**$141**	**$113**	**$10**	**($11)**	**($11)**	**($6)**	**($18)**	**($4)**	**($2)**	**$1**	**$1**	**($4)**	**$19**
Total EBITDA Margin	**0.0%**	**3.6%**	**10.2%**	**17.1%**	**13.6%**	**7.0%**	**-20.9%**	**-22.5%**	**-10.7%**	**-5.9%**	**-6.1%**	**-2.3%**	**1.3%**	**1.6%**	**-1.1%**	**4.8%**
Interest Expense	(10)	(14)	(16)	(15)	(39)	(10)	(9)	(9)	(15)	(43)	(9)	(9)	(9)	(9)	(34)	(34)
Other Income (expense)	0	0	(5)	(2)	7	1	1	0	0	2	0	0	0	0	0	0
Income Taxes	($3)	$16	$3	($4)	($3)	($0)	$0	$0	$7	$7	$6	$6	$5	$5	$23	$19
Tax Rate	*-89%*	*24%*	*12%*	*9%*	*0%*	*-3%*	*1%*	*0%*	*21%*	*6%*	*22%*	*23%*	*23%*	*23%*	*23%*	*23%*
Net Income	**($39)**	**($71)**	**($68)**	**($53)**	**($218)**	**($301)**	**($24)**	**($18)**	**($27)**	**($371)**	**($22)**	**($20)**	**($18)**	**($18)**	**($78)**	**($65)**
Diluted Shares (Avg)	24	24	25	25	29	29	29	30	30	30	30	30	30	30	30	30
EPS (Adjusted, Diluted)	**($0.27)**	**($2.14)**	**($0.98)**	**$1.54**	**($0.16)**	**($0.51)**	**($1.14)**	**($1.13)**	**($0.92)**	**($3.70)**	**($0.73)**	**($0.67)**	**($0.60)**	**($0.60)**	**($2.58)**	**($2.14)**
Dividend per Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	80	(10)	(35)	(19)	36	1	21	20	25	68	(19)	1	7	18	8	(13)
Cash from Operations	**$140**	**($3)**	**$6**	**$90**	**$101**	**$1**	**$2**	**$2**	**$12**	**$16**	**($26)**	**($3)**	**$5**	**$16**	**($8)**	**($9)**
Capital Expenditures	($27)	($9)	($45)	($47)	($65)	($1)	($2)	($4)	($2)	($9)	($5)	($6)	($5)	$6	($10)	($12)
Cash from Investing	**($19)**	**($4)**	**($44)**	**($390)**	**($34)**	**$1**	**$1**	**($2)**	**($2)**	**($2)**	**($5)**	**($6)**	**($5)**	**$6**	**($10)**	**($12)**
Increase (decrease) in Debt	($127)	($6)	($4)	$177	($36)	($4)	($4)	$0	$0	($7)	$0	$0	$0	$0	$0	$0
Cash from Financing	**($127)**	**($7)**	**$52**	**$347**	**($38)**	**($4)**	**($4)**	**$0**	**$0**	**($8)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$19**	**$4**	**$17**	**$64**	**$93**	**$90**	**$89**	**$80**	**$89**	**$89**	**$59**	**$50**	**$50**	**$72**	**$72**	**$50**
Balance Sheet ($ in millions)																
Total Assets	**$658**	**$576**	**$579**	**$1,141**	**$851**	**$535**	**$469**	**$438**	**$416**	**$416**	**$405**	**$393**	**$383**	**$374**	**$374**	**$335**
Long-term Debt, Net of Current	**250**	**244**	**0**	**425**	**392**	**379**	**366**	**343**	**343**	**343**	**343**	**343**	**343**	**343**	**343**	**343**
Stockholder Equity	353	288	287	595	390	92	70	54	28	28	10	(7)	(21)	(36)	(36)	(83)
Cash Flow Metrics																
Free Cash Flow	**$114**	**($12)**	**($40)**	**$43**	**$36**	**($0)**	**($0)**	**($2)**	**$10**	**$7**	**($31)**	**($9)**	**$0**	**$22**	**($17)**	**($21)**
FCF/share (diluted)	$0.00	($0.51)	($1.61)	$1.74	$1.24	($0.00)	($0.02)	($0.06)	$0.32	$0.24	($1.02)	($0.30)	$0.00	$0.73	($0.58)	($0.70)
Operating Free Cash Flow	**$0**	**$0**	**($51)**	**($33)**	**$83**	**($6)**	**$18**	**($14)**	**$2**	**($1)**	**($35)**	**($11)**	**($0)**	**$20**	**($27)**	**($24)**
Balance Sheet Metrics																
Book Value (per share)	$14.48	$11.83	$11.70	$24.12	$13.25	$3.12	$2.38	$1.80	$0.95	$0.95	$0.32	($0.23)	($0.71)	($1.18)	($1.18)	($2.74)
Net Debt	**$231**	**$240**	**$224**	**$361**	**$300**	**$290**	**$279**	**$265**	**$255**	**$255**	**$286**	**$294**	**$294**	**$272**	**$272**	**$294**
Total Debt/Capital	41.4%	45.9%	45.7%	41.7%	50.2%	80.5%	84.0%	86.6%	92.4%	92.4%	97.3%	102.0%	106.6%	111.5%	111.5%	131.9%
Net Debt/Capital	28.3%	31.3%	30.5%	27.4%	30.3%	43.2%	44.4%	45.4%	47.4%	47.4%	49.2%	50.6%	51.9%	53.5%	53.5%	58.3%
Return on equity	-3.8%	-16.3%	-8.4%	8.6%	-0.9%	-24.7%	-166.3%	-219.0%	-266.8%	-52.5%	-457.8%	-5798.2%	513.0%	253.3%	2134.5%	109.3%
Return on capital (Net Debt)	**4.1%**	**-7.4%**	**-2.0%**	**7.1%**	**4.2%**	**-3.6%**	**-26.8%**	**-29.6%**	**-20.8%**	**-14.3%**	**-20.7%**	**-18.3%**	**-16.3%**	**-17.8%**	**-19.6%**	**-17.1%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

NOW Inc. (DNOW)

The Year Ahead for DNOW

After being one of the best performers in our coverage group off the March trough, DNOW has since recoupled with the broader group (DNOW -41% YTD v. OSX -41%, MRC -50%) as the relative attractiveness of its strong balance sheet wore off through 2020 as EBITDA prospects looked more bleak. We continue to view risks to the stock as relatively balanced heading into 2021, as we believe the current valuation implies organic growth and/or non-dilutive acquisitive growth that will be difficult for DNOW to achieve near-term, as we see a difficult path back to meaningfully positive EBITDA. In 2021 we expect revenue to build off of the 4Q20 trough, but still to fall -9% y/y as the international recovery likely takes time to gain momentum and DNOW's U.S. sales lag the broader upstream recovery due to non-drilling and completions exposure. Gross margins have been impressive YTD, topping >21% the past two quarters ex-inventory charges, and the company made meaningful progress on cost reductions during the downturn, lowering WS&A to $83mm in 3Q20 (from ~$135mm/qtr in 2019). This sets up a better profitability starting point for 2021 than we expected a few months ago, though we still model margins sliding back to ~21% and see more work to be done on reigning in costs. Cash generation has also been good in 2020 (FCF +$126mm YTD), driven largely by working capital liquidation, which should no longer be a tailwind in 2021, leading us to model FCF inverting modestly negative next year (JPMe -$22mm).

Things to Focus On in 2021

- **U.S. to lead 2021 top line growth; gross margins to remain strong.** DNOW's 4Q20 guidance suggests a trough for overall revenue as international activity continues to fall and U.S. seasonality are expected to send domestic sales lower q/q despite increasing D&C activity. We think this creates a constructive setup for U.S. sales early in 2021 as DNOW's volumes catch up with rebounding activity, while internationally the bias will be higher v. the 2020 exit but progress is likely slower. In 2021 we think GM% can remain fairly strong at ~21% since pricing largely bottomed in 2020, with less material inventory charges.
- **M&A is being actively considered, possible route to expand EBITDA.** Despite the lack of EBITDA, DNOW has an enviable balance sheet position, with $325mm net cash as of 9/30. The company indicated it is actively vetting M&A, which we think would most likely be to expand its midstream and downstream footprints (where MRC is the market leader). However DNOW will likely be very selective with any potential transactions and avoid taking on debt to finance M&A. The strategy could be effective in giving DNOW a path back to better EBITDA, but finding the right strategic fit and valuation could prove challenging.
- **Additional cost savings through digital, but may not be enough for positive FCF.** DNOW has been moving in the right direction with cost reductions in 2020, but the company indicated that it has more to achieve in this arena (as we've long advocated). We think the reduction in physical locations and buildout of DNOW's digital offerings will be key to these efforts in 2021. Currently about one-third of sales are from the digital platform, and these are dominated by DNOW's largest customers, suggesting further opportunity by integrating additional customers onto the platform. Even with our expectation for WS&A to average $83-84mm/qtr in 2021, we think DNOW will burn cash in most periods next year as we believe more volume growth will be needed to generate sufficient cash without the benefit of working capital liquidations.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 33: NOW Inc Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
United States Revenue	$2,027	$1,445	$1,914	$2,371	$2,240	$441	$260	$228	$210	$1,139	$241	$265	$279	$273	$1,058	$1,125
Canada Revenue	378	258	356	358	319	78	41	42	41	202	45	38	44	42	170	173
International Revenue	605	404	378	398	392	85	69	56	52	262	53	55	57	59	224	244
Total Revenue	**$3,010**	**$2,107**	**$2,648**	**$3,127**	**$2,951**	**$604**	**$370**	**$326**	**$302**	**$1,602**	**$340**	**$359**	**$380**	**$374**	**$1,452**	**$1,543**
COGS	($2,508)	($1,762)	($2,147)	($2,497)	($2,365)	($487)	($290)	($255)	($238)	($1,270)	($269)	($284)	($300)	($295)	($1,148)	($1,217)
Gross Margin	16.7%	16.4%	18.9%	20.1%	19.9%	19.4%	21.6%	21.8%	21.2%	20.7%	20.9%	20.9%	21.0%	21.0%	21.0%	21.1%
Total Costs & Expenses	**($3,121)**	**($2,316)**	**($2,682)**	**($3,054)**	**($2,906)**	**($617)**	**($387)**	**($338)**	**($323)**	**($1,665)**	**($352)**	**($368)**	**($383)**	**($378)**	**($1,482)**	**($1,549)**
Total D&A	($38)	($53)	($50)	($41)	($41)	($10)	($7)	($6)	($7)	($29)	($7)	($7)	($7)	($7)	($28)	($28)
EBITDA	($71)	($158)	$7	$109	$87	$2	($3)	($1)	($14)	($15)	($6)	($2)	$4	$2	($2)	$22
EBITDA Margin	-2.0%	-7.9%	0.7%	3.6%	4.9%	3.6%	3.8%	5.7%	5.4%	4.9%	3.6%	3.8%	5.7%	5.4%	4.9%	4.9%
Total Operating Income Companywide	**($111)**	**($209)**	**($34)**	**$72**	**$45**	**($8)**	**($9)**	**($7)**	**($21)**	**($45)**	**($13)**	**($9)**	**($3)**	**($4)**	**($29)**	**($6)**
Total Operating Margin	-3.7%	-9.9%	-1.3%	2.3%	1.5%	-1.3%	-2.4%	-2.1%	-6.8%	-2.8%	-3.8%	-2.4%	-0.8%	-1.2%	-2.0%	-0.4%
Income Taxes	$37	$64	$14	($24)	($9)	$0	($7)	($1)	$5	($3)	$3	$2	$1	$1	$7	$2
Tax Rate	*38%*	*30%*	*33%*	*38%*	*26%*	*1%*	*-64%*	*-14%*	*22%*	*-7%*	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*
Net Income	**($501)**	**($232)**	**($52)**	**$52**	**($97)**	**($331)**	**($30)**	**($22)**	**($16)**	**($399)**	**($10)**	**($7)**	**($2)**	**($3)**	**($22)**	**($6)**
Diluted Shares (Avg)	107	107	108	109	109	109	109	109	109	109	109	109	109	109	109	109
EPS (Adjusted, diluted)	**($0.56)**	**($1.37)**	**($0.27)**	**$0.36**	**$0.24**	**($0.07)**	**($0.16)**	**($0.07)**	**($0.15)**	**($0.46)**	**($0.09)**	**($0.06)**	**($0.02)**	**($0.03)**	**($0.20)**	**($0.05)**
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	300	342	(135)	(46)	98	(9)	70	55	23	139	(1)	2	(12)	(6)	(17)	(2)
Cash from Operations	**$324**	**$235**	**($115)**	**$73**	**$224**	**$6**	**$68**	**$59**	**$14**	**$147**	**($3)**	**$3**	**($8)**	**($2)**	**($11)**	**$20**
Capital expenditures	($11)	($4)	($4)	($11)	($12)	($3)	($2)	($2)	($2)	($9)	($3)	($3)	($3)	($3)	($11)	($9)
Cash from Investing	**($523)**	**($183)**	**$8**	**($9)**	**($22)**	**$22**	**($2)**	**($1)**	**($2)**	**$17**	**($3)**	**($3)**	**($3)**	**($3)**	**($11)**	**($9)**
Increase (decrease) in LT Debt	$108	($43)	$97	($30)	($132)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash from Financing	**$106**	**($47)**	**$94**	**($37)**	**($138)**	**($2)**	**($2)**	**($2)**	**$0**	**($6)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$90**	**$106**	**$98**	**$116**	**$183**	**$202**	**$269**	**$325**	**$337**	**$337**	**$331**	**$331**	**$320**	**$315**	**$315**	**$327**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	165	143	119	106	120	112	109	101	96	96	92	88	84	79	79	60
Total Assets	**$1,832**	**$1,603**	**$1,749**	**$1,795**	**$1,591**	**$1,196**	**$1,069**	**$1,039**	**$1,000**	**$1,000**	**$1,009**	**$1,015**	**$1,021**	**$1,015**	**$1,015**	**$1,016**
Long-term Debt, Net of Current	**$108**	**$65**	**$162**	**$132**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Stockholder Equity	$1,403	$1,183	$1,185	$1,214	$1,144	$768	$747	$731	$715	$715	$705	$699	$696	$693	$693	$687
Cash Flow Metrics																
Free Cash Flow	**$313**	**$231**	**($119)**	**$62**	**$212**	**$3**	**$66**	**$57**	**$12**	**$138**	**($6)**	**($0)**	**($11)**	**($5)**	**($22)**	**$11**
FCF/share (diluted)	$2.93	$2.16	($1.10)	$0.57	$1.94	$0.03	$0.60	$0.52	$0.11	$1.26	($0.06)	($0.00)	($0.10)	($0.04)	($0.20)	$0.11
Balance Sheet Metrics																
Book Value (per share)	$13	$11	$11	$11	$10	$7	$7	$7	$7	$7	$6	$6	$6	$6	$6	$6
Net Debt	**$18**	**($41)**	**$64**	**$16**	**($183)**	**($202)**	**($269)**	**($325)**	**($337)**	**($337)**	**($331)**	**($331)**	**($320)**	**($315)**	**($315)**	**($327)**
Total Debt/Capital	7.1%	5.2%	12.0%	9.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net Debt/Capital	1.3%	(3.6%)	5.1%	1.3%	(19.0%)	(35.7%)	(56.3%)	(80.0%)	(89.1%)	(89.1%)	(88.3%)	(89.8%)	(85.0%)	(83.4%)	(83.4%)	(90.5%)
Return on equity	(3.5%)	(11.4%)	(2.4%)	3.3%	2.2%	(3.4%)	(9.5%)	(4.3%)	(8.9%)	(5.4%)	(5.4%)	(3.7%)	(1.3%)	(1.9%)	(3.1%)	(0.8%)
Return on capital (Net Debt)	**(3.7%)**	**(11.3%)**	**(2.1%)**	**3.6%**	**2.6%**	**(4.1%)**	**(11.3%)**	**(7.2%)**	**(16.3%)**	**(7.5%)**	**(10.2%)**	**(7.1%)**	**(2.5%)**	**(3.6%)**	**(5.8%)**	**(1.5%)**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Oceaneering (OII)

The Year Ahead for OII

OII's shares have clawed back a lot of ground since reporting a 3Q earnings beat (+149% v. OSX +77%), though we question the long-term sustainability of the achievement as more offshore headwinds come into view in 2021. OII is currently guiding for flat EBITDA y/y in 2021, supported by any remaining cost-out boosting EBITDA. OII has initiated ~$140mm in cost savings, a small portion of which may bleed into 2021; the company's newly realigned segments should (at least theoretically) help bolster margins through operational efficiencies. We model revenue declining in 2021 to ~$1.66bn (JPMe -9% y/y) but EBITDA improving slightly (if below management's expectations) to ~$157mm, given OII's ability to preserve margin in 2H21 is more uncertain as self-help dries up. Considering the offshore trajectory and the run the shares have had of their October lows, we remain cautious on the fundamentals to support the stock heading into and post-2021.

Things to Focus On in 2021

- **The road to flat EBITDA in 2021 ain't an easy one.** Though the offshore cycle remains challenging with limited visibility past the current environment, OII presented the potential building blocks for it to generate roughly flat EBITDA y/y in 2021. Though we are modeling slightly below that at ~$157mm (befitting our historical skepticism of OII guidance), we expect remaining cost-out to be significant contributors to this number. The Angola project in Offshore Projects may also serve as a contributor if it goes through in 1Q21 instead of 2020. Preserving margin in 2H21 will be critical to hitting this target, yet uncertainty around where it is coming from remains.

- **Balance sheet de-risking continues.** OII has been able to generate healthy FCF thanks to a CARES Tax refund of $16-34mm and improved working capital management. Cash flow is expected to be significantly higher in 2021 (JPMe ~$115mm) due to a large unwind of Product receivables associated with the project milestone payments and any remaining tax refunds. However, OII has still found ways to deploy growth capital, and indicated the need to in Subsea Robotics going forward. Given the uncertainty surrounding offshore services, we think management's predilection towards growth capital could be a headwind to cash preservation. As its outstanding debt (RCF due 2023) comes closer in view, the resiliency of EBITDA in 2021 will be an important determinate of OII's course of action.

- **2H20 trajectory will be telling**. The government-focused ADTech should prove to be a stable contributor to both revenue and margins in 2021 (JPMe +4%/+60bps y/y), but the majority of OII's revenue (~80%) is exposed to the offshore environment and COVID-19 headwinds on the entertainment business. The trajectory in 2H20 after the larger part of current backlog and projects on the horizon are worked through will be an indicator of the overall direction of the company, as well as expectations for 2022.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 34: Oceaneering Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Subsea Robotics						140	119	120	104	482	109	105	106	103	423	106
Manufactured Products						167	101	110	119	497	127	110	91	70	398	62
Offshore Projects						74	74	73	62	284	67	70	73	67	277	67
Integrity Management & Digital Solutions						65	54	54	49	221	55	53	54	50	212	52
Aerospace and Defense Technologies						91	80	83	87	340	91	84	87	91	353	87
Total Revenue	**$3,063**	**$2,272**	**$1,922**	**$1,909**	**$2,048**	**$537**	**$427**	**$440**	**$420**	**$1,824**	**$449**	**$422**	**$411**	**$382**	**$1,664**	**$1,563**
COGS	(2448)	(1992)	(1727)	(1780)	(1950)	(490)	(385)	(410)	(389)	(1674)	(406)	(382)	(373)	(346)	(1507)	(1424)
SG&A	(232)	(208)	(184)	(198)	(215)	(56)	(48)	(49)	(44)	(197)	(47)	(44)	(41)	(38)	(170)	(151)
Total Costs & Expenses	**($2,680)**	**($2,201)**	**($1,911)**	**($1,973)**	**($2,165)**	**($546)**	**($432)**	**($459)**	**($433)**	**($1,871)**	**($454)**	**($425)**	**($414)**	**($384)**	**($1,677)**	**($1,575)**
Total D&A	**($241)**	**($241)**	**($241)**	**($215)**	**($201)**	**($52)**	**($39)**	**($39)**	**($40)**	**($171)**	**($41)**	**($41)**	**($41)**	**($41)**	**($164)**	**($167)**
EBITDA	**$669**	**$370**	**$225**	**$143**	**$162**	**$52**	**$40**	**$45**	**$32**	**$169**	**$42**	**$40**	**$38**	**$36**	**$157**	**$139**
EBITDA Margins	21.8%	16.3%	11.7%	7.5%	7.9%	9.7%	9.5%	10.3%	7.5%	9.3%	9.4%	9.6%	9.3%	9.5%	9.4%	8.9%
Operating Income																
Subsea Robotics						16	13	12	4	45	4	4	4	4	15	3
Manufactured Products						8	5	(36)	5	(17)	7	6	2	(0)	14	(0)
Offshore Projects						(4)	(3)	0	(1)	(8)	0	1	1	1	3	1
Integrity Management & Digital Solutions						4	(0)	1	(0)	4	(0)	(0)	(0)	(0)	(1)	(0)
Aerospace and Defense Technologies						13	13	14	14	54	15	14	15	15	59	14
Unallocated	(114)	(84)	(101)	(109)	(121)	(25)	(28)	(26)	(30)	(110)	(24)	(24)	(24)	(24)	(98)	(24)
Total Operating Income Companywide	**$428**	**$135**	**$13**	**($61)**	**($32)**	**$12**	**$1**	**($35)**	**($9)**	**($31)**	**$1**	**($1)**	**($3)**	**($5)**	**($7)**	**($28)**
Total Operating Margins	14.0%	6.0%	0.7%	-3.2%	-1.6%	2.2%	0.1%	-8.0%	-2.1%	-1.7%	0.3%	-0.1%	-0.6%	-1.3%	-0.4%	-1.8%
Interest Income	1	4	7	10	8	1	1	0	0	2	0	0	0	0	0	5
Interest Expense	(25)	(25)	(28)	(38)	(43)	(12)	(12)	(9)	(10)	(43)	(12)	(12)	(12)	(12)	(48)	(48)
Other Expense, net	(6)	(5)	(2)	(2)	(6)	(6)	(3)	(3)	(3)	(14)	0	0	0	0	0	0
Income Taxes	($127)	($38)	$2	$22	($16)	$9	($5)	($12)	$4	($3)	$2	$3	$3	$4	$12	$15
Tax Rate	*32%*	*35%*	*24%*	*24%*	*-21%*	*169%*	*-34%*	*-200%*	*20%*	*-4%*	*22%*	*22%*	*21%*	*22%*	*22%*	*21%*
Net Income	**$231**	**$25**	**($12)**	**($149)**	**$169**	**($368)**	**($29)**	**($79)**	**($17)**	**($493)**	**($8)**	**($10)**	**($12)**	**($13)**	**($43)**	**($55)**
Diluted Shares (Avg)	99	98	99	99	99	99	99	99	99	99	99	99	99	99	99	99
EPS (Adjusted, Diluted)	**$2.74**	**$0.73**	**($0.08)**	**($0.71)**	**($0.89)**	**$0.04**	**($0.18)**	**($0.18)**	**($0.17)**	**($0.50)**	**($0.08)**	**($0.10)**	**($0.12)**	**($0.13)**	**($0.43)**	**($0.56)**
Dividend per Share	$1.08	$0.96	$0.45	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Cash from Operations	**$560**	**$341**	**$136**	**$37**	**$158**	**($32)**	**$38**	**$27**	**$80**	**$112**	**$89**	**$55**	**$1**	**$25**	**$171**	**$65**
Capital Expenditures	($200)	($109)	($94)	($110)	($148)	($27)	($11)	($8)	($11)	($57)	($13)	($14)	($15)	($15)	($57)	($54)
Cash from Investing	**($437)**	**($170)**	**($94)**	**($186)**	**($139)**	**($27)**	**($9)**	**($3)**	**($11)**	**($50)**	**($13)**	**($14)**	**($15)**	**($15)**	**($56)**	**($53)**
Increase (decrease) in LT Debt	$0	$0	$0	($4)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cash from Financing	**($157)**	**($97)**	**($44)**	**($6)**	**($2)**	**($2)**	**($0)**	**$0**	**$0**	**($2)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$385**	**$450**	**$430**	**$354**	**$374**	**$307**	**$334**	**$359**	**$427**	**$427**	**$504**	**$546**	**$531**	**$541**	**$541**	**$551**
Balance Sheet ($ in millions)																
Total Assets	**$3,430**	**$3,574**	**$3,024**	**$3,325**	**$2,741**	**$2,165**	**$2,129**	**$2,038**	**$2,041**	**$2,041**	**$2,040**	**$2,026**	**$2,003**	**$1,975**	**$1,975**	**$1,932**
Long-term Debt, Net of Current	**796**	**793**	**792**	**787**	**797**	**806**	**806**	**806**	**806**	**806**	**806**	**806**	**806**	**806**	**806**	**806**
Stockholder Equity	1,579	1,853	1,665	1,915	1,075	637	625	559	553	553	545	535	524	510	510	455
Cash Flow Metrics																
Free Cash Flow	**$360**	**$232**	**$43**	**($73)**	**$10**	**($59)**	**$27**	**$19**	**$68**	**$55**	**$77**	**$42**	**($15)**	**$10**	**$113**	**$10**
FCF/share (diluted)	$3.65	$2.36	$0.43	($0.74)	$0.10	($0.60)	$0.27	$0.19	$0.69	$0.55	$0.77	$0.42	($0.15)	$0.10	$1.14	$0.10
Operating Free Cash Flow	**$544**	**$390**	**$131**	**$52**	**($7)**	**$28**	**$22**	**$23**	**$22**	**$94**	**$32**	**$29**	**$26**	**$24**	**$112**	**$100**
Balance Sheet Metrics																
Book Value (per share)	$15.98	$18.86	$16.90	$19.41	$10.88	$6.43	$6.30	$5.63	$5.57	$5.57	$5.49	$5.39	$5.27	$5.14	$5.14	$4.58
Net Debt	**$411**	**$343**	**$362**	**$432**	**$423**	**$499**	**$472**	**$447**	**$378**	**$378**	**$302**	**$260**	**$275**	**$265**	**$265**	**$255**
Total Debt/Capital	33.5%	30.0%	32.2%	29.1%	42.6%	55.9%	56.3%	59.0%	59.3%	59.3%	59.6%	60.1%	60.6%	61.2%	61.2%	63.9%
Net Debt/Capital	20.6%	15.6%	17.9%	18.4%	28.2%	43.9%	43.0%	44.4%	40.6%	40.6%	35.6%	32.7%	34.4%	34.2%	34.2%	35.9%
Return on equity	16.7%	4.2%	-0.4%	-3.9%	-5.9%	1.7%	-11.5%	-11.9%	-12.3%	-35.7%	-6.1%	-7.3%	-8.8%	-10.2%	-33.6%	-48.5%
Return on capital (Net Debt)	**13.9%**	**3.6%**	**-0.3%**	**-3.1%**	**-4.2%**	**-0.2%**	**-5.1%**	**-3.6%**	**-6.2%**	**-14.8%**	**-3.8%**	**-4.8%**	**-5.8%**	**-6.7%**	**-22.2%**	**-31.1%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Oil States International (OIS)

The Year Ahead for OIS

Despite a strong balance sheet and history of generating free cash flow, OIS's shares have not been gifted by the market (-68% YTD v. OSX -41%). After successfully amending its cash flow-based revolver to an asset-based facility and easing worries of covenant trips, the company has reduced net debt by ~$130mm as of 3Q. Going forward, we think improvements to EBITDA and profitability are needed for the shares to sustain their recent value-factor-led bounce. OIS has been able to thin losses thanks to cost-out and came to near-breakeven in 3Q; we expect recovery in 4Q to be the turning point for margins into 2021 (JPMe +290bps y/y). Customer timing and delays on orders caused O/MP to miss expectations in the back half of 2020, but with a near industry-leading book:bill of ~0.9x in 3Q and a growing international foundation (e.g., Guyana and Brazil), we expect the segment to stabilize in 2021 as OIS pursues more traditional work (JPMe -9% y/y). That said, the segment also has more bespoke opportunities in subsea mining and offshore wind which could be catalysts for (longer-term) growth. As OIS awaits macro help, we anticipate it to prioritize technology, asset diversification, and cash preservation.

Things to Focus On in 2021

- **All eyes on DT to lead the way.** While the market saw a surge in conventional units sold at bottom of the cycle pricing in 3Q, we view that as more transitory. With a shift back to integrated as activity recovers, we think OIS will seek to reclaim lost market share with its own premium offerings. As a result, we model the segment recovering +18% y/y in 2021 as customer acceptance increases and the pricing pressure eases up.
- **Short cycle business shrinking, leaving less optimism for margin growth.** While self-help from cost savings and expected growth from new products should help nudge margins back into positive territory in 2021, OIS's ability to expand them at the pace of prior cycles seems less likely given the growing contribution from short-cycle exposures. The uncertain outlook for macro help serves as a headwind to growth for its long-cycle business.
- **Not much more to do on balance sheet de-risking.** While we expect OIS to remain focused on managing working capital, we anticipate a shift to improving EBITDA and reclaiming profitability. Future debt repayments likely rely on the strength of EBITDA, and more macro help is needed before that can be significant. Liquidity should remain strong; the nearest maturity on its debt is in 2023, and the company believes it could likely be undrawn on the RCF by the time the amendment expires.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 35: Oil States International Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
Well Site Services Revenue	$376	$186	$289	$480	$432	$87	$36	$37	$39	$200	$48	$53	$60	$56	$217	$265
Dow nhole Technology Revenue		72	166	214	182	41	15	19	23	98	27	29	30	30	115	142
Offshore/Manufactured Products Revenue	724	509	382	394	403	91	95	79	78	343	78	78	78	77	311	303
Total Revenue	**$1,100**	**$694**	**$671**	**$1,088**	**$1,017**	**$220**	**$146**	**$135**	**$140**	**$641**	**$153**	**$159**	**$167**	**$163**	**$642**	**$710**
EBITDA																
Completion Services EBITDA	51.2	(10.6)	20.0	64.9	61.6	11.9	(5.0)	(0.8)	0.0	6.1	2.5	4.0	6.0	4.9	17.3	34.2
Drilling Services EBITDA	9.6	(0.6)	4.7	5.4	0.4	0.1	(0.4)	0.5	0.2	0.4	0.4	0.4	0.5	0.5	1.8	2.4
Well Site Services	60.8	(11.2)	24.7	70.3	62.1	12.0	(5.4)	(0.3)	0.2	6.5	2.8	4.4	6.5	5.4	19.1	36.6
Dow nhole Technology		0.4	37.1	50.5	23.7	5.3	(5.5)	(1.0)	0.7	(0.5)	2.3	3.1	3.5	3.5	12.4	21.3
Offshore/Manufactured Products	175.1	114.0	63.9	63.1	63.1	13.1	15.0	9.4	9.2	46.7	9.2	9.1	9.1	9.0	36.3	34.8
Corporate and Elimination	(45.9)	(47.4)	(50.6)	(51.2)	(44.3)	(8.5)	(8.5)	(8.0)	(7.0)	(32.1)	(6.9)	(7.2)	(7.5)	(7.3)	(28.9)	(31.9)
EBITDA Companywide	**190.1**	**55.4**	**38.0**	**133**	**105**	**21.9**	**(4.5)**	**0.1**	**3.1**	**21**	**7.4**	**9.4**	**11.5**	**10.6**	**39**	**61**
Well Site Services EBITDA Margins	16.2%	-6.0%	8.6%	14.6%	14.4%	13.7%	-15.0%	-0.8%	0.6%	3.2%	5.9%	8.3%	10.8%	9.7%	8.8%	13.8%
Dow nhole Technology EBITDA Margins		0.6%	22.3%	23.6%	13.0%	13.0%	-36.8%	-5.2%	2.9%	-0.5%	8.4%	10.7%	11.8%	11.8%	10.7%	15.0%
Offshore Products EBITDA Margins	24.2%	22.4%	16.7%	16.0%	15.7%	14.3%	15.8%	12.0%	11.8%	13.6%	11.8%	11.7%	11.7%	11.7%	11.7%	11.5%
Total EBITDA Margins	**17.3%**	**8.0%**	**5.7%**	**12.2%**	**10.3%**	**10.0%**	**-3.1%**	**0.1%**	**2.2%**	**3.2%**	**4.9%**	**5.9%**	**6.9%**	**6.5%**	**6.1%**	**8.5%**
Total D&A	(127.9)	(118.7)	(107.7)	(123.5)	(123.3)	(26.4)	(24.6)	(24.3)	(23.1)	(98.4)	(22.5)	(22.6)	(22.6)	(22.5)	(90.3)	(92.3)
Total Operating Income Companywide	**$61.6**	**($63.5)**	**($69.7)**	**$9.1**	**($19.5)**	**($4.5)**	**($33.3)**	**($30.8)**	**($20.0)**	**($88.7)**	**($15.0)**	**($13.3)**	**($11.1)**	**($11.9)**	**($51.4)**	**($31.6)**
Total Operating Margins	**5.6%**	**-9.1%**	**-10.4%**	**0.8%**	**-1.9%**	**-2.1%**	**-22.8%**	**-22.9%**	**-14.3%**	**-13.9%**	**-9.8%**	**-8.3%**	**-6.6%**	**-7.3%**	**-8.0%**	**-4.5%**
Income Taxes	(18)	25	20	(0)	1	(0)	12	8	5	24	3	3	3	3	12	9
Tax Rate	*32%*	*37%*	*27%*	*-1%*	*3%*	*-2%*	*37%*	*28%*	*20%*	*26%*	*19%*	*19%*	*19%*	*22%*	*20%*	*21%*
Net Income	**$27.5**	**($45.8)**	**($84.6)**	**($19.3)**	**($231.8)**	**($405.0)**	**($24.4)**	**($20.0)**	**($18.6)**	**($468.0)**	**($14.5)**	**($13.1)**	**($11.3)**	**($11.5)**	**($50.4)**	**($33.9)**
Diluted Shares (Avg)	$50.3	$50.2	$50.2	$58.7	$59.4	$59.7	$59.8	$59.9	$59.9	$59.8	$59.9	$59.9	$59.9	$59.9	$59.9	$59.9
EPS (Adjusted, diluted)	**$0.77**	**($0.85)**	**($1.07)**	**($0.14)**	**($0.60)**	**($0.14)**	**($0.33)**	**($0.33)**	**($0.31)**	**($1.11)**	**($0.24)**	**($0.22)**	**($0.19)**	**($0.19)**	**($0.84)**	**($0.57)**
Dividend per Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	78	97	32	(23)	39	(15)	42	51	(1)	78	(6)	(9)	9	15	8	(32)
Cash from Operations	**$256**	**$159**	**$95**	**$105**	**$137**	**$5**	**$39**	**$87**	**$7**	**$138**	**$5**	**$4**	**$24**	**$30**	**$63**	**$41**
Capital expenditures	(115)	(30)	(35)	(88)	(56)	(6)	(3)	(2)	(4)	(15)	(4)	(4)	(4)	(4)	(17)	(19)
Cash from Investing	**($146)**	**($30)**	**($48)**	**($461)**	**($52)**	**($2)**	**($2)**	**$1**	**($4)**	**($7)**	**($4)**	**($4)**	**($4)**	**($4)**	**($17)**	**($19)**
Increase (decrease) in Debt	(18)	(60)	(43)	336	(91)	15	(7)	(61)	0	(53)	0	0	0	0	0	0
Cash from Financing	**($125)**	**($64)**	**($65)**	**$324**	**($96)**	**$12**	**($7)**	**($62)**	**$0**	**($57)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$36**	**$69**	**$53**	**$19**	**$8**	**$24**	**$54**	**$80**	**$83**	**$83**	**$84**	**$83**	**$103**	**$129**	**$129**	**$151**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	639	553	499	540	460	429	409	391	372	372	354	335	317	298	298	224
Total Assets	**$1,599**	**$1,384**	**$1,302**	**$2,004**	**$1,728**	**$1,312**	**$1,247**	**$1,181**	**$1,153**	**$1,153**	**$1,144**	**$1,139**	**$1,136**	**$1,124**	**$1,124**	**$1,105**
Long-term Debt, Net of Current	129	45	5	306	223	239	229	164	164	164	164	164	164	164	164	164
Stockholder Equity	1,256	1,204	1,133	1,440	1,224	803	779	764	750	750	739	729	722	714	714	695
Cash Flow Metrics																
Free Cash Flow	**$141.3**	**$129.0**	**$60.2**	**$17.3**	**$81.3**	**($0.4)**	**$35.6**	**$84.6**	**$3.1**	**$122.9**	**$0.7**	**($0.3)**	**$20.1**	**$25.8**	**$46.2**	**$22.1**
FCF/share (diluted)	$2.81	$2.57	$1.20	$0.29	$1.37	($0.01)	$0.60	$1.41	$0.05	$2.06	$0.01	($0.01)	$0.34	$0.43	$0.77	$0.37
Operating Free Cash Flow	**($82.9)**	**($65.9)**	**($22.7)**	**$105.4**	**($7.2)**	**($7.9)**	**($41.4)**	**($11.0)**	**($30.7)**	**($91.0)**	**$9.4**	**$14.5**	**($1.3)**	**($10.3)**	**$12.3**	**$65.5**
Balance Sheet Metrics																
Book Value (per share)	$24.95	$24.00	$22.58	$24.52	$20.61	$13.45	$13.02	$12.77	$12.52	$12.53	$12.34	$12.18	$12.06	$11.92	$11.92	$11.60
Net Debt	**$93**	**($23)**	**($49)**	**$287**	**$214**	**$241**	**$201**	**$109**	**$106**	**$106**	**$106**	**$106**	**$86**	**$60**	**$60**	**$38**
Total Debt/Capital	9.3%	3.6%	0.4%	17.5%	15.4%	24.8%	24.7%	19.8%	20.1%	20.1%	20.4%	20.6%	20.8%	20.9%	20.9%	21.4%
Net Debt/Capital	6.9%	(2.0%)	(4.5%)	16.6%	14.9%	23.1%	20.5%	12.5%	12.4%	12.4%	12.5%	12.7%	10.6%	7.8%	7.8%	5.2%
Return on equity	3.0%	(3.4%)	(4.6%)	(0.6%)	(2.7%)	(3.3%)	(10.0%)	(10.4%)	(9.8%)	(6.8%)	(7.8%)	(7.1%)	(6.2%)	(6.4%)	(6.9%)	(4.8%)
Return on capital (Net Debt)	**3.1%**	**(3.1%)**	**(4.4%)**	**0.8%**	**(1.2%)**	**(1.5%)**	**(6.8%)**	**(7.5%)**	**(7.4%)**	**(4.9%)**	**(5.7%)**	**(5.1%)**	**(4.4%)**	**(4.7%)**	**(5.1%)**	**(3.3%)**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Patterson-UTI Energy (PTEN)

The Year Ahead for PTEN

Patterson's drilling business has held market share relatively well during the downturn, with its fleet falling just -33% in 2Q20 (v. BKR rig count -50%), to which we give the company credit. However as drilling demand recovers in 4Q20 and into 2021, we are cautious that the stability of the company's customer base that helped it hold activity steadier in the downturn also limits PTEN's upside "torque" to a rising broader rig count. The company's guidance to average just one additional active rig q/q in 4Q20 aligns with our more conservative activity expectations heading into 2021. For pressure pumping, Patterson still looks to be on the wrong side of the frac "have" / "have not" divide, and we think the business will struggle to stand out in a market that is growing increasingly concentrated among the four largest providers. PTEN has continued to generate positive FCF through 2020, and we expect this to continue in 2021, aided by capex near maintenance-only levels. Combined with a solid balance sheet and far out maturity wall (2028) we see Patterson as fully capable of navigating a protracted downturn, but see greater upside elsewhere.

Things to Focus On in 2021

- **Extent of upside capture in L-48 drilling recovery.** The change in PTEN's 4Q20 active rig count is guided to lag the BKR count in large part due to rigs returning from idle-but-contracted (IBC) status, since these are included in the headline contracted rig count figure. Beyond this, we think Patterson's U.S. land rig market share is likely to average low-20% in 2021 (from a peak of ~25% in 3Q20). Exposure to gassier basins lends stability to PTEN's activity, but with our outlook for oil basins (particularly the Permian) to account for the majority of rig additions in 2021, we think the geographic mix will be less of a boon next year.

- **PTEN focused on defending frac profitability and positioning within the industry.** Pressure pumping is becoming more consolidated than in prior cycles, with several lower-quality players exiting the market or severely reducing fleet sizes. Patterson demonstrated this year that its pumping business could remain EBITDA positive even in the depths of the downturn, and the company is committed to maintaining a presence in the market. Guidance for six fleets to be active in 4Q20 (up from four in 2Q20) shows us that PTEN can capture some incremental frac demand, but we are cautious as the company may lag pure-play peers in ramping up activity in 1H21 and expanding margins as operators seek to align with the most efficient and tech-focused pumpers.

- **Ability to sustain good cash generation.** Patterson slashed 2020 capex by ~40% from its initial guidance and cut its dividend in half (a relatively small commitment at ~$15mm/yr, but a move in the right direction) in response to the market downturn. These actions helped PTEN generate positive FCF through 2020 and build up its cash position to ~$304mm. Combined with $600mm available on an undrawn RCF, PTEN is in a strong liquidity position, and has most of its debt due in 2028+. While the balance sheet is generally not a concern, with cash generation growing more constrained in 2021, we think Patterson needs to demonstrate how it can return to a stronger FCF position in order to garner more interest from investors.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 36: Patterson-UTI Energy Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
Contract Drilling Revenue	$1,123	$544	$1,040	$1,430	$1,308	$267	$171	$109	$111	$658	$122	$137	$144	$144	$548	$665
Pressure Pumping Revenue	712	354	1,200	1,573	869	125	60	72	78	334	101	110	115	112	438	451
Other Services Revenue	25	18	71	114	105	19	8	10	10	47	11	12	13	13	48	57
Other Revenue	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	**$1,860**	**$915**	**$2,357**	**$3,327**	**$2,471**	**$446**	**$250**	**$201**	**$212**	**$1,109**	**$249**	**$275**	**$290**	**$286**	**$1,100**	**$1,252**
COGS	(1232)	(649)	(1719)	(2402)	(1774)	(327)	(165)	(141)	(161)	(794)	(198)	(219)	(232)	(231)	(880)	(989)
SG&A	(83)	(69)	(105)	(134)	(134)	(30)	(24)	(22)	(22)	(99)	(22)	(22)	(22)	(22)	(88)	(86)
Total Costs & Expenses	(1315)	(704)	(1811)	(2527)	(1894)	(358)	(198)	(164)	(183)	(904)	(219)	(242)	(254)	(253)	(968)	(1075)
Total D&A	(705)	(666)	(754)	(850)	(801)	(187)	(165)	(157)	(157)	(666)	(157)	(155)	(154)	(153)	(619)	(606)
EBITDA	**$569**	**$212**	**$546**	**$802**	**$598**	**$88**	**$62**	**$37**	**$29**	**$215**	**$29**	**$34**	**$35**	**$33**	**$131**	**$177**
Total Operating Income Companywide	**($161)**	**($454)**	**($209)**	**($50)**	**($204)**	**($99)**	**($103)**	**($121)**	**($128)**	**($451)**	**($128)**	**($122)**	**($119)**	**($120)**	**($488)**	**($429)**
Total Operating Margins	-9%	-50%	-9%	-1%	-8%	-22%	-41%	-60%	-60%	-41%	-51%	-44%	-41%	-42%	-44%	-34%
Income Taxes	57	176	84	17	49	14	13	13	18	58	27	26	25	25	102	89
Tax Rate	*29%*	*36%*	*35%*	*18%*	*20%*	*14%*	*11%*	*10%*	*13%*	*12%*	*20%*	*20%*	*20%*	*20%*	*20%*	*19%*
Net Income	**($323)**	**($319)**	**$6**	**($321)**	**($426)**	**($435)**	**($150)**	**($112)**	**($120)**	**($817)**	**($110)**	**($105)**	**($103)**	**($103)**	**($422)**	**($375)**
Diluted Shares (Avg)	146	146	199	219	203	191	187	187	187	188	187	187	187	188	187	188
EPS (Adjusted, diluted)	**($0.95)**	**($2.17)**	**($0.81)**	**($0.35)**	**($0.98)**	**($0.45)**	**($0.56)**	**($0.63)**	**($0.64)**	**($2.28)**	**($0.59)**	**($0.56)**	**($0.55)**	**($0.55)**	**($2.25)**	**($2.00)**
Dividend per Share	$0.40	$0.16	$0.08	$0.14	$0.16	$0.04	$0.02	$0.02	$0.02	$0.10	$0.02	$0.02	$0.02	$0.02	$0.08	$0.08
Additional Information ($000)																
Contract Drilling U.S.																
Revenue Days	43,708	22,975	49,751	63,971	54,282	11,188	7,450	5,499	5,630	29,767	6,004	6,677	7,223	7,223	27,128	32,460
Day Rate	23.9	21.9	20.7	22.2	24.0	23.8	21.8	19.7	19.7	21.3	20.3	20.5	20.0	20.0	20.2	20.5
Day Cost	-13.3	-12.8	-13.3	-13.7	-14.4	-14.5	-11.7	-10.6	-12.3	-12.3	-13.8	-14.2	-14.1	-14.1	-14.1	-14.1
Day Margin	10.5	9.1	7.3	8.5	9.6	9.3	10.2	9.0	7.5	9.0	6.5	6.3	5.8	5.9	6.1	6.3
Contract Drilling Canada																
Revenue Days	1,484	621	676	508	262	47	0	0	0	47	0	0	0	0	0	0
Day Rate	25.1	25.7	20.4	17.7	17.7	20.0	0.0	0.0	0.0	6.7	0.0	0.0	0.0	0.0	0.0	0.0
Day Cost	-22.1	-27.5	-17.1	-17.3	-26.4	-25.4	0.0	0.0	0.0	-8.5	0.0	0.0	0.0	0.0	0.0	0.0
Day Margin	3.0	-1.8	3.3	0.5	-8.8	-5.4	0.0	0.0	0.0	-1.8	0.0	0.0	0.0	0.0	0.0	0.0
Pressure Pumping																
Fracturing jobs	610	352	622	812	505	89	35	69	76	269	99	109	114	112	433	445
Revenue / fracturing job	1,123	987	1,841	1,904	1,688	1,359	1,550	961	941	1,203	941	932	932	923	932	932
Other jobs	2,080	799	1,262	1,081	844	209	152	180	198	739	257	283	297	291	1,129	1,162
Revenue / other job	14	11	17	21	27	20	35	32	31	29	31	31	31	30	31	31
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	387	96	(171)	(45)	135	(15)	97	23	(7)	99	(4)	(8)	(7)	(1)	(19)	(13)
Cash from Operations	**$999**	**$305**	**$301**	**$731**	**$696**	**$73**	**$146**	**$69**	**$30**	**$318**	**$43**	**$42**	**$44**	**$49**	**$178**	**$218**
Capital expenditures	(744)	(120)	(502)	(641)	(348)	(72)	(50)	(13)	(15)	(150)	(31)	(33)	(34)	(34)	(131)	(146)
Cash from Investing	**($723)**	**($98)**	**($1,011)**	**($585)**	**($302)**	**($68)**	**($47)**	**($13)**	**($15)**	**($143)**	**($31)**	**($33)**	**($34)**	**($34)**	**($131)**	**($146)**
Increase (decrease) in Debt	(131)	(255)	268	253	(176)	0	(0)	(0)	(0)	(0)	0	0	0	0	0	0
Cash from Financing	**($199)**	**($285)**	**$717**	**$57**	**($465)**	**($28)**	**($5)**	**($4)**	**($4)**	**($40)**	**($4)**	**($4)**	**($4)**	**($4)**	**($15)**	**($15)**
Cash at End of Period	**$113**	**$35**	**$43**	**$245**	**$174**	**$152**	**$247**	**$298**	**$309**	**$315**	**$324**	**$330**	**$336**	**$347**	**$347**	**$404**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (net)	3,921	3,409	4,255	4,003	3,307	3,187	3,034	2,895	2,714	2,714	2,588	2,465	2,345	2,226	2,226	1,766
Total Assets	**$4,533**	**$3,805**	**$5,759**	**$5,470**	**$4,440**	**$3,870**	**$3,625**	**$3,500**	**$3,382**	**$3,382**	**$3,285**	**$3,189**	**$3,095**	**$2,984**	**$2,984**	**$2,609**
Long-term Debt, Net of Current	791	598	867	1,119	967	967	967	967	967	967	967	967	967	967	967	967
Stockholder Equity	2,561	2,249	3,982	3,505	2,834	2,379	2,229	2,113	1,989	1,989	1,875	1,766	1,659	1,552	1,552	1,162
Cash Flow Metrics																
Free Cash Flow	**$256**	**$185**	**($201)**	**$89**	**$349**	**$1**	**$96**	**$55**	**$15**	**$168**	**$13**	**$10**	**$10**	**$15**	**$47**	**$72**
FCF/share (diluted)	1.75	1.27	(1.01)	0.41	1.72	0.01	0.52	0.29	0.08	0.89	0.07	0.05	0.05	0.08	0.25	0.39
Operating Free Cash Flow	**($315)**	**$119**	**$378**	**$131**	**$118**	**$26**	**($79)**	**$29**	**$18**	**($7)**	**$20**	**$23**	**$24**	**$14**	**$80**	**$91**
Balance Sheet Metrics																
Book Value (per share)	$18	$15	$20	$16	$14	$12	$12	$11	$11	$11	$10	$9	$9	$8	$8	$6
Net Debt	**$742**	**$563**	**$824**	**$874**	**$792**	**$815**	**$720**	**$664**	**$652**	**$652**	**$643**	**$638**	**$632**	**$620**	**$620**	**$563**
Total Debt/Capital	25.0%	21.0%	17.9%	24.2%	25.4%	28.9%	30.3%	31.4%	32.7%	32.7%	34.0%	35.4%	36.8%	38.4%	38.4%	45.4%
Net Debt/Capital	22.5%	20.0%	17.1%	20.0%	21.9%	25.5%	24.4%	23.9%	24.7%	24.7%	25.5%	26.5%	27.6%	28.6%	28.6%	32.6%
Return on equity	(5.1%)	(13.2%)	(5.1%)	(2.1%)	(6.3%)	(13.1%)	(18.2%)	(21.9%)	(23.5%)	(17.8%)	(22.8%)	(23.2%)	(24.0%)	(25.8%)	(23.8%)	(27.6%)
Return on capital (Net Debt)	**(3.2%)**	**(9.5%)**	**(3.6%)**	**(0.8%)**	**(4.0%)**	**(8.9%)**	**(12.4%)**	**(15.2%)**	**(16.3%)**	**(12.4%)**	**(15.7%)**	**(15.6%)**	**(16.0%)**	**(16.9%)**	**(16.0%)**	**(17.3%)**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

ProPetro Holding (PUMP)

The Year Ahead for PUMP

ProPetro appears positioned to put a tumultuous 2020 behind it and move forward as a key beneficiary of recovering Permian frac activity in 2021. The company became current on outstanding SEC filings earlier in the year and completed major management changes with the appointment of David Schorlemer as CFO, making constructive progress on moving past the corporate tail risks that dogged the stock. Activity hit a deep trough in 2Q with four effectively utilized fleets as completions in oil basins came to a near-halt in the spring. However, work has turned around in 2H20, and we think PUMP's Permian-only focus will be an advantage for 2021 as we expect the basin will capture an outsized share of incremental activity. As such we anticipate PUMP growing its active fleet count from the 9-10 guided for 4Q20 up to the mid-teens by mid-2021. With improved operational efficiencies on more activity and potential for pricing to (modestly) inflect higher, we model annualized EBITDA/fleet (ex-idle fees) returning to low-DD $mm in 2021.

Things to Focus On in 2021

- **Utilization ramp up in 1H21, possible inflection higher for pricing.** We believe that a material build up in frac activity will be needed in early-2021 in order for E&Ps to meet broad guidance for 2021 annual production to hold flat relative to 4Q20. This is especially true for the oil basins, and particularly the Permian as the core of U.S. crude production. As such we model ProPetro building its active fleet count from 9-10 in 4Q20 to the mid-teens in 2021. Accompanying this uptrend in utilization will potentially be some (modest) pricing increase as well, since as the L-48 fleet count approaches ~150 contractors will need to re-staff idle fleets, and should demand better terms from customers to cover the costs. Even at this higher fleet count, we expect PUMP will still have 2-3 idle fleets with PXD and continue to earn $5-6mm in annual EBITDA from idle fees on each fleet.
- **DuraStim fleets set to see first standalone use.** PUMP's DuraStim investment ended up being a drag in in 2020, but with frac activity set to return more strongly in 2021 and ESG taking on a growing role in operator decision-making, we think ProPetro should be able to garner better utilization of its DuraStim fleets. PUMP has been testing the equipment as constituents of conventional fleets, potentially giving it a head start relative to peers only just beginning to test e-frac (see: NEX). At least one full DuraStim fleet is guided to deploy on a standalone basis at some point in 2021 by ProPetro, though until more is known about its operations we don't assume any economic premium for this fleet relative to its conventional counterparts. Equipment for three DuraStim fleets has been delivered, however no power source has yet been procured for the third, potentially necessitating a further capital outlay (or some other solution) in order to put the third fleet to work on a standalone basis.
- **We see positive FCF in 2021 even with maintenance costs creeping up.** With more than ten fleets expected to be running in 2021, PUMP loses some ability to use sidelined equipment to reduce maintenance costs, and therefore guides to annualized maintenance capex per fleet of ~$8mm (v. ~$6mm in 2020). Even still, we model ProPetro generating modestly positive cash in 2021. Combined with a net cash balance sheet, we think the company is in a strong financial position to compete in the unfolding NAM frac recovery.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 37: ProPetro Holding Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Pressure Pumping revenue	510	409	945	1,658	2,002	387	104	131	146	768	188	227	249	249	912	1,022
Other Services revenue	59	28	37	46	51	8	2	2	3	15	3	4	4	4	14	17
Total Revenue	**$570**	**$437**	**$982**	**$1,705**	**$2,052**	**$395**	**$106**	**$134**	**$148**	**$783**	**$191**	**$230**	**$252**	**$253**	**$926**	**$1,038**
COGS	(483)	(404)	(814)	(1271)	(1470)	(301)	(68)	(100)	(118)	(587)	(154)	(183)	(198)	(197)	(732)	(808)
SG&A	(27)	(27)	(29)	(45)	(63)	(19)	(13)	(17)	(11)	(60)	(10)	(10)	(10)	(10)	(40)	(39)
Total Costs & Expenses	**($510)**	**($429)**	**($844)**	**($1,316)**	**($1,533)**	**($320)**	**($81)**	**($116)**	**($130)**	**($647)**	**($163)**	**($193)**	**($208)**	**($207)**	**($771)**	**($847)**
Total D&A	**($50)**	**($44)**	**($56)**	**($88)**	**($145)**	**($40)**	**($40)**	**($37)**	**($36)**	**($154)**	**($36)**	**($37)**	**($37)**	**($34)**	**($144)**	**($145)**
Total Gross Profit	**$86**	**$33**	**$168**	**$434**	**$582**	**$94**	**$38**	**$34**	**$30**	**$196**	**$37**	**$47**	**$55**	**$56**	**$195**	**$230**
Total Gross Margins	15.1%	7.5%	17.1%	25.5%	28.4%	23.8%	35.7%	25.5%	20.2%	25.1%	19.5%	20.4%	21.6%	22.1%	21.0%	22.2%
EBITDA																
Pressure Pumping EBITDA	63	16	145	398	534	79	34	27	28	168	36	45	52	53	187	219
Other Services EBITDA	(2)	(8)	(8)	(10)	(15)	(4)	(9)	(9)	(9)	(31)	(8)	(8)	(8)	(7)	(31)	(27)
EBITDA Companywide	**$60**	**$8**	**$137**	**$389**	**$519**	**$75**	**$25**	**$17**	**$19**	**$137**	**$28**	**$37**	**$44**	**$46**	**$155**	**$191**
Total EBITDA Margin	10.6%	1.8%	14.0%	22.8%	25.3%	19.0%	23.9%	13.0%	12.7%	17.4%	14.5%	16.1%	17.6%	18.1%	16.7%	18.4%
Interest Expense	(22)	(20)	(7)	(7)	(7)	(1)	(1)	(0)	0	(2)	0	0	0	0	0	0
Other Income (expense)	(0)	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes	$5	$20	($24)	($59)	($50)	$1	$6	$8	$2	$17	$1	($0)	($1)	($1)	($1)	($6)
Tax Rate	*42%*	*35%*	*32%*	*20%*	*14%*	*-3%*	*42%*	*38%*	*12%*	*86%*	*12%*	*12%*	*12%*	*12%*	*12%*	*12%*
Net Income	**($45)**	**($52)**	**$13**	**$174**	**$164**	**($8)**	**($26)**	**($29)**	**($15)**	**($78)**	**($7)**	**$0**	**$6**	**$11**	**$10**	**$41**
Diluted Shares (Avg)	35	35	79	87	104	101	101	101	101	101	101	101	101	101	101	102
EPS (Adjusted, Diluted)	**($0.20)**	**($1.04)**	**$0.64**	**$2.69**	**$3.05**	**$0.34**	**($0.09)**	**($0.12)**	**($0.15)**	**($0.03)**	**($0.07)**	**$0.00**	**$0.06**	**$0.11**	**$0.10**	**$0.40**
Dividend per Share	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Additional Segment Information																
Total Frac Fleets	10	10	13	19	27	28	29	31	31	30	31	31	31	31	31	31
Active Frac Fleets	10	10	13	19	24	19	4	9	9	10	12	15	16	16	15	17
% Frac Utilization	*100%*	*100%*	*94%*	*99%*	*90%*	*68%*	*14%*	*27%*	*31%*	*35%*	*40%*	*47%*	*52%*	*53%*	*48%*	*53%*
Total horsepower	420	420	566	860	1,415	1,415	1,415	1,415	1,487	1,433	1,487	1,487	1,487	1,487	1,487	1,487
Active horsepower	420	420	534	842	1,270	957	195	388	463	501	605	718	789	803	729	808
Average Revenue per Active Fleet (annualized)	$51.0	$40.9	$75.6	$84.5	$78.9	$79.0	$98.6	$58.7	$58.4	$73.7	$57.4	$58.5	$58.4	$57.5	$58.0	$58.6
EBITDA per Active Fleet (annualized)	$6.3	$1.6	$11.6	$20.2	$21.2	$16.1	$33.5	$12.2	$11.6	$18.4	$11.3	$12.0	$12.6	$12.6	$12.1	$12.9
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	38	20	(16)	16	(20)	(11)	19	7	2	18	(7)	(6)	(3)	(5)	(21)	0
Cash from Operations	**$81**	**$11**	**$109**	**$393**	**$455**	**$62**	**$35**	**$21**	**$23**	**$141**	**$22**	**$31**	**$40**	**$39**	**$133**	**$186**
Capital Expenditures	($63)	($43)	($286)	($284)	($503)	($47)	($33)	($6)	($25)	($112)	($25)	($29)	($32)	($33)	($119)	($133)
Cash from Investing	**($63)**	**($42)**	**($281)**	**($281)**	**($495)**	**($47)**	**($31)**	**($4)**	**($25)**	**($107)**	**($25)**	**($29)**	**($32)**	**($33)**	**($119)**	**($133)**
Increase (decrease) in Debt	($15)	($72)	($106)	($2)	$60	($20)	($110)	$0	$0	($130)	$0	$0	$0	$0	$0	$0
Cash from Financing	**($15)**	**$130**	**$63**	**($4)**	**$56**	**($20)**	**($110)**	**($0)**	**$0**	**($131)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$34**	**$134**	**$24**	**$133**	**$149**	**$144**	**$37**	**$54**	**$53**	**$53**	**$49**	**$51**	**$59**	**$66**	**$66**	**$119**
Balance Sheet ($ in millions)																
Total Assets	**$446**	**$541**	**$719**	**$1,275**	**$1,436**	**$1,400**	**$1,094**	**$1,096**	**$1,083**	**$1,083**	**$1,094**	**$1,111**	**$1,124**	**$1,134**	**$1,134**	**$1,177**
Long-term Debt, Net of Current	**237**	**159**	**57**	**70**	**130**	**110**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Stockholder Equity	70	221	413	797	969	962	938	912	896	896	889	889	895	906	906	947
Cash Flow Metrics																
Free Cash Flow	**$18**	**($32)**	**($177)**	**$109**	**$45**	**$14**	**$2**	**$15**	**($2)**	**$30**	**($3)**	**$2**	**$8**	**$6**	**$13**	**$53**
FCF/share (diluted)	$0.00	($0.92)	($2.24)	$1.25	$0.44	$0.14	$0.02	$0.15	($0.02)	$0.30	($0.03)	$0.02	$0.08	$0.06	$0.13	$0.53
Operating Free Cash Flow	**($13)**	**($26)**	**($183)**	**$38**	**($68)**	**$22**	**($12)**	**$31**	**($2)**	**$39**	**($3)**	**$2**	**$8**	**$6**	**$13**	**$53**
Balance Sheet Metrics																
Book Value (per share)	$1.99	$6.32	$5.24	$9.17	$9.34	$9.55	$9.31	$9.04	$8.88	$8.89	$8.79	$8.79	$8.84	$8.94	$8.95	$9.32
Net Debt	**$219**	**$43**	**$49**	**($63)**	**($19)**	**($34)**	**($37)**	**($54)**	**($53)**	**($53)**	**($49)**	**($51)**	**($59)**	**($66)**	**($66)**	**($119)**
Total Debt/Capital	78.4%	44.4%	15.0%	8.1%	11.8%	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net Debt/Capital	43.1%	13.9%	9.6%	-9.3%	-2.0%	-3.8%	-4.3%	-6.8%	-6.6%	-6.6%	-6.2%	-6.5%	-7.6%	-8.5%	-8.5%	-16.8%
Return on equity	-20.2%	-25.1%	16.0%	38.7%	35.8%	14.2%	-3.8%	-5.4%	-6.8%	-0.3%	-3.3%	0.1%	2.8%	4.8%	1.1%	4.4%
Return on capital (Net Debt)	**3.8%**	**-8.5%**	**15.4%**	**40.1%**	**38.3%**	**15.2%**	**-3.8%**	**-5.7%**	**-7.2%**	**-0.3%**	**-3.6%**	**0.1%**	**2.9%**	**5.1%**	**1.2%**	**4.9%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Schlumberger (SLB)

The Year Ahead for SLB

Schlumberger's transformation made substantial progress amid the pandemic this year while all nine of CEO Olivier Le Peuch's (OLP) strategical elements were unveiled. The recent re-segmentation keeps the focus on digital with the fit-for-basin approach and capital stewardship paramount in all strategic decisions. This deliberate pivot is accompanied by a bogey to deliver +20% EBITDA margins exiting 2021; after strong cost-out execution this year, we think it looks to be in sight. The OneStim sale is a critical lever, set to close by yearend, further reducing SLB's direct (and dilutive) NAM exposure. With 80% international mix going forward, Schlumberger remains at the mercy of the int'l E&P capex cycle, which came into sharper investor focus at the 3Q report with seemingly weak 2021 expectations. We remain below the Street on top line but model better margins (on further cost-out efficacy), putting us mostly in-line for 2021. With new financials highlighting Digital and OneStim's exit likely baked in Street numbers, we remain wary of SLB and its "watched pot" history as the new digital narrative potentially takes hold. On our normalized FCF/EV estimates, SLB is yielding a relatively uncompetitive ~6%, so we remain patient and wait for a more bearish E&P capex cycle to be priced in.

Things to Focus On in 2021

- **If you have nothing nice to say (on the int'l capex cycle), perhaps it's best to not say anything at all.** SLB expects international revenue to account for ~80% of its mix post-OneStim divestiture, so when 2021 commentary on the 3Q call was limited, the stock began its latest bout of underperformance. It looks like int'l activity will tick lower in 4Q on seasonality with risk of another leg down in 2021 on reset budgets; SLB (fairly) characterized the next few quarters as a transition period, but how long that lasts remains up for debate. While LatAm continues to rebound from very low levels, activity in the Middle East has yet to trough, a region where SLB noted cancelations in legacy RC. Additionally, any glimpse of an offshore recovery is a +2022 story in our view, hurting SLB relative to peers.
- **New financials showcase high-flying Digital margins.** As part of the strategic pivot, SLB released new financials with Digital & Integration sporting 27% EBIT margins in 3Q20 and the other three divisions in the 8-9% range. While Digital should easily outgrow core-OFS, the rearrangement doesn't dramatically change the capabilities of the whole portfolio, and we still expect ~10% companywide EBIT margins in 2022, helped by the sale of the dilutive OneStim business in 4Q. With SLB's strong cost-out execution, we are modeling ~21% companywide EBITDA margins in 2021 which is in-line with OLP's goal.
- **Stringent capital allocation deployment should remain through-cycle.** SLB has reduced capex intensity to ~4.5% of sales in 2020 v. ~11% in 2012, and believes 5% is a reasonable run-rate. With OneStim sold, APS not requiring more balance sheet to finance projects, and investor appetite for M&A lacking, it appears there is considerably less capital wood to chop. Management's pivot has largely been well-received, though we retain some wariness of the engrained mentality of growth over value, which could be tested as digital's opportunity set unfolds. We continue to model a "normalized" 7% capex/sales ratio.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 38: Schlumberger Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Digital & Integration				3,820	4,145	885	619	739	771	3,014	732	766	816	862	3,175	3,503
Reservoir Performance				10,050	9,299	1,969	1,170	1,215	1,166	5,520	1,120	1,142	1,154	1,119	4,534	4,763
Well Construction				11,310	11,880	2,815	2,089	1,835	1,817	8,556	1,762	1,797	1,815	1,761	7,136	7,643
Production Systems				8,168	8,167	1,912	1,557	1,532	1,563	6,564	1,516	1,501	1,516	1,485	6,017	6,322
Total Revenue	**$35,474**	**$27,810**	**$30,440**	**$32,815**	**$32,917**	**$7,455**	**$5,356**	**$5,258**	**$5,252**	**$23,321**	**$5,067**	**$5,143**	**$5,235**	**$5,164**	**$20,609**	**$21,957**
North America	$9,811	$6,665	$9,486	$11,983	$10,843	$2,279	$1,183	$1,157	$1,193	$5,812	$992	$1,049	$1,101	$1,072	$4,214	$4,698
Latin America	6,014	4,231	$3,977	3,735	4,149	945	543	707	721	2,916	663	644	624	599	2,531	2,525
Europe/Africa/CIS	9,284	7,352	$7,048	7,144	7,683	1,751	1,449	1,397	1,327	5,924	1,221	1,197	1,149	1,091	4,657	4,574
Middle East/Asia	9,898	9,285	$9,419	9,557	10,018	2,426	2,146	1,987	2,010	8,569	2,190	2,254	2,361	2,401	9,206	10,160
Total Costs & Expenses	**($29,910)**	**($25,525)**	**($27,762)**	**($29,623)**	**($29,909)**	**($6,924)**	**($5,148)**	**($4,846)**	**($4,771)**	**($21,689)**	**($4,629)**	**($4,676)**	**($4,730)**	**($4,654)**	**($18,690)**	**($19,685)**
Total D&A	($4,078)	($4,094)	($3,837)	($3,556)	($3,589)	($792)	($604)	($587)	($593)	($2,576)	($604)	($608)	($613)	($617)	($2,442)	($2,441)
EBITDA	**$9,820**	**$6,442**	**$6,824**	**$6,807**	**$6,610**	**$1,340**	**$831**	**$1,011**	**$1,073**	**$4,255**	**$1,042**	**$1,075**	**$1,118**	**$1,126**	**$4,361**	**$4,712**
Operating Income																
Digital & Integration				882	882	151	108	202	223	684	191	211	241	269	911	1,060
Reservoir Performance				1,169	992	134	22	103	110	369	107	111	114	107	438	484
Well Construction				1,465	1,429	331	180	172	182	865	177	184	188	177	727	828
Production Systems				843	847	191	145	132	150	618	147	144	147	141	578	639
Eliminations & Other	467	(273)	(581)	(172)	(172)	(31)	(59)	(34)	(32)	(156)	(31)	(31)	(31)	(31)	(124)	(128)
Corporate & Other	(768)	(925)	(934)	(936)	(957)	(228)	(169)	(151)	(153)	(701)	(153)	(153)	(153)	(153)	(611)	(611)
Total Operating Income Companywide	**$5,742**	**$2,348**	**$2,987**	**$3,251**	**$3,021**	**$548**	**$227**	**$424**	**$481**	**$1,680**	**$438**	**$467**	**$505**	**$509**	**$1,918**	**$2,271**
Income Taxes	($1,102)	($306)	($471)	($465)	($399)	($75)	($22)	($59)	($71)	($227)	($64)	($69)	($78)	($79)	($291)	($363)
Tax Rate	*20%*	*16%*	*18%*	*17%*	*16%*	*17%*	*23%*	*20%*	*20%*	*19%*	*20%*	*20%*	*20%*	*20%*	*20%*	*20%*
Net Income	**$2,072**	**($1,687)**	**($1,507)**	**$2,135**	**($10,137)**	**($7,376)**	**($3,434)**	**($82)**	**$285**	**($10,607)**	**$237**	**$269**	**$306**	**$307**	**$1,119**	**$1,467**
Diluted Shares (Avg)	1,275	1,347	1,392	1,393	1,390	1,387	1,388	1,391	1,391	1,389	1,391	1,391	1,391	1,391	1,391	1,391
EPS (Adjusted, Diluted)	**$3.36**	**$1.15**	**$1.50**	**$1.62**	**$1.48**	**$0.25**	**$0.05**	**$0.16**	**$0.21**	**$0.67**	**$0.17**	**$0.19**	**$0.22**	**$0.22**	**$0.80**	**$1.05**
Dividend per Share	$2.00	$2.00	$2.00	$2.00	$2.00	$0.13	$0.13	$0.13	$0.13	$0.50	$0.13	$0.13	$0.13	$0.13	$0.50	$0.50
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	(366)	(246)	(823)	(442)	(327)	(480)	83	(399)	162	(598)	80	(179)	(70)	200	31	(103)
Cash from Operations	**$8,805**	**$6,261**	**$5,663**	**$5,713**	**$5,431**	**$784**	**$803**	**$479**	**$615**	**$2,827**	**$796**	**$624**	**$774**	**$1,049**	**$3,242**	**$3,505**
Capital Expenditures	($2,410)	($2,055)	($2,107)	($2,160)	($1,724)	($407)	($251)	($200)	($200)	($1,058)	($226)	($236)	($244)	($245)	($952)	($1,074)
Cash from Investing	**($10,252)**	**($624)**	**($1,586)**	**($1,952)**	**($2,114)**	**($1,312)**	**($547)**	**($740)**	**($255)**	**($2,854)**	**($296)**	**($306)**	**($314)**	**($315)**	**($1,232)**	**($1,414)**
Increase (decrease) in LT Debt	$5,794	($1,990)	($1,525)	($1,395)	($986)	$1,385	$530	$111	($500)	$1,526	$0	$0	($665)	$0	($665)	($1,895)
Cash from Financing	**$1,374**	**($5,428)**	**($6,105)**	**($4,302)**	**($3,692)**	**$777**	**($167)**	**$21**	**($674)**	**($43)**	**($174)**	**($174)**	**($839)**	**($174)**	**($1,361)**	**($2,591)**
Balance Sheet ($ in millions)																
Multiclient Seismic Data	$1,026	$1,073	$727	$601	$568	$556	$356	$344	$339	$339	$339	$339	$338	$337	$337	$355
Total Assets	**$68,005**	**$77,956**	**$71,987**	**$70,507**	**$56,312**	**$48,594**	**$44,667**	**$44,066**	**$42,771**	**$42,771**	**$42,497**	**$42,232**	**$41,643**	**$41,419**	**$41,419**	**$40,252**
Long-term Debt, Net of Current	**14,442**	**16,463**	**14,875**	**14,644**	**14,770**	**15,409**	**16,763**	**16,471**	**15,971**	**15,971**	**15,971**	**15,971**	**15,306**	**15,306**	**15,306**	**13,411**
Stockholder Equity	35,905	41,529	37,261	36,586	24,176	15,983	12,456	12,369	11,630	11,630	11,433	11,369	11,342	11,316	11,316	11,410
Cash Flow Metrics																
Free Cash Flow	**$4,956**	**$2,545**	**$1,671**	**$2,472**	**$2,695**	**$179**	**$465**	**$226**	**$360**	**$1,230**	**$500**	**$318**	**$460**	**$734**	**$2,011**	**$2,090**
FCF/share (diluted)	$3.89	$1.89	$1.20	$1.78	$1.94	$0.13	$0.34	$0.16	$0.26	$0.89	$0.36	$0.23	$0.33	$0.53	$1.45	$1.50
Operating Free Cash Flow	**$8,082**	**$5,378**	**$5,492**	**$5,074**	**$4,926**	**$621**	**$2,446**	**$447**	**$1,391**	**$4,905**	**$686**	**$617**	**$756**	**$982**	**$3,041**	**$3,353**
Balance Sheet Metrics																
Book Value (per share)	$28.16	$30.83	$26.78	$26.27	$17.39	$11.52	$8.97	$8.89	$8.36	$8.37	$8.22	$8.17	$8.15	$8.14	$8.11	$8.18
Net Debt	**$5,547**	**$10,121**	**$13,110**	**$13,274**	**$13,127**	**$13,298**	**$13,777**	**$13,926**	**$13,740**	**$13,740**	**$13,414**	**$13,270**	**$12,984**	**$12,424**	**$12,482**	**$11,193**
Total Debt/Capital	34.6%	32.1%	32.8%	30.5%	38.7%	51.0%	58.2%	59.0%	59.7%	59.7%	60.2%	60.3%	59.4%	59.5%	59.5%	56.4%
Net Debt/Capital	13.4%	19.6%	26.0%	26.6%	35.2%	45.4%	52.5%	53.0%	54.2%	54.2%	54.0%	53.9%	53.4%	52.3%	52.5%	49.6%
Return on equity	11.6%	4.0%	5.3%	6.1%	6.8%	7.0%	1.9%	7.3%	9.5%	5.2%	8.2%	9.4%	10.8%	10.8%	9.7%	12.9%
Return on capital (Net Debt)	**10.6%**	**4.3%**	**4.9%**	**5.4%**	**5.8%**	**5.5%**	**2.5%**	**5.1%**	**6.0%**	**4.3%**	**5.4%**	**6.0%**	**6.6%**	**6.7%**	**6.2%**	**7.9%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Select Energy Services (WTTR)

The Year Ahead for WTTR

While a clear market leader with an impeccable balance sheet, we see Select as relatively disadvantaged to its completions-levered smid-cap peers in 2021 for three reasons. First, WTTR doesn't offer as high a degree of operating leverage as frac peers, limiting margin expansion potential as activity recovers. Second, Select has a relatively elevated (and fixed asset-based) Bakken exposure, which we think could be a drag in 2021 as growth is concentrated in the Permian. Finally, the company has fewer paths to regain pricing power than other smid-caps given customers' ability to self-source. That said, we give Select credit for its pristine balance sheet, flexible capital model, diversified, blue-chip customer base, and ability to avoid burning cash. These features are key differentiators from some other UW-rated names in our coverage with more existential financial risks. Across WTTR's segments, we see the best top line growth setup in 2021 for Water Services and Chemicals as demand recovers with rising frac activity in 1H21, while Water Infrastructure volumes likely grow more slowly due to the outsized Bakken exposure.

Things to Focus On in 2021

- **Water Services and Chemicals to lead WTTR's top line growth in 2021.** With our view for L-48 completions activity to ramp up materially in 1H21, we think Select's frac-oriented Water Services and Chemicals businesses have the best growth runway laid out in 2021. WS gross margin has been disappointing recently though at ~3%, and we think it will be difficult for WTTR to grow WS GM% beyond low-DD in 2021 (v. +20% in 2019) given the relatively higher variable costs associated with the business. In Chemicals, GM% has recovered after dipping into negative territory in 2Q, and we expect the segment can achieve "normalized" GM% of low-teens in 2021, comparable to last cycle.

- **Water Infrastructure volumes should pick up in 4Q20, but additional growth looks slow.** Select guided to WI top line of $20mm+ in 4Q20 (v. $16mm in 3Q20) with much of the growth attributable to Bakken flows resuming after being curtailed during the downturn. Our outlook for 2021 growth in the Bakken is milder than other oil basins, however, and though flows on the Permian fixed pipeline should rise as activity builds in early 2021, we think it will be by a smaller amount than overall completions. Therefore we see more modest growth prospects for WI in 2021 than for Select's other businesses. We think WTTR can achieve 30-35% WI incremental margins in the coming quarters, and as such we anticipate WI GM% will be bound to the low-20% range through 2021.

- **Pristine balance sheet and low maintenance costs allow optionality for capital allocation, but attractive opportunities may be limited.** Select continued to deliver respectable cash flow in 2020, but we think in the coming quarters FCF may dip towards breakeven in some periods as working capital normalizes. Capex discipline has been key to delivering positive FCF recently, and we think WTTR can keep maintenance costs at a low level through 2021. On top of maintenance spending, Select intends to allocate some capital to organic growth primarily centered on technologies to improve water reuse and reduce emissions, and is open to considering M&A next year. With a net cash balance sheet we see ample ability to pursue such opportunities, but remain cautious on the incremental growth they could provide. Select has a history of returning cash to shareholders and reiterated this as a core long-term priority, but with our current market outlook we think cash returns are likely to remain on hold in 2021.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 39: Select Energy Services Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Water Services revenue				897	772	150	56	55	56	315	62	71	74	69	276	296
Water Infrastructure revenue				230	222	58	15	16	21	110	22	24	24	23	94	96
Oilfield Chemicals revenue			42	260	269	71	21	31	33	155	37	41	43	41	163	175
Total Revenue	**$536**	**$302**	**$692**	**$1,529**	**$1,292**	**$278**	**$92**	**$101**	**$109**	**$581**	**$121**	**$136**	**$142**	**$133**	**$532**	**$567**
COGS	(419)	(252)	(483)	(1200)	(1026)	(237)	(90)	(94)	(99)	(521)	(107)	(117)	(122)	(115)	(462)	(486)
SG&A	(57)	(35)	(56)	(99)	(112)	(25)	(18)	(16)	(15)	(73)	(12)	(13)	(12)	(12)	(49)	(48)
Total Costs & Expenses	**($475)**	**($286)**	**($539)**	**($1,285)**	**($1,094)**	**($254)**	**($96)**	**($104)**	**($114)**	**($568)**	**($120)**	**($130)**	**($134)**	**($127)**	**($511)**	**($534)**
Total D&A	**($105)**	**($97)**	**($103)**	**($133)**	**($121)**	**($27)**	**($26)**	**($25)**	**($24)**	**($101)**	**($23)**	**($23)**	**($22)**	**($22)**	**($90)**	**($78)**
Total Gross Profit	**$117**	**$51**	**$210**	**$329**	**$266**	**$41**	**$2**	**$7**	**$10**	**$60**	**$14**	**$19**	**$20**	**$18**	**$71**	**$81**
Total Gross Margins	21.8%	16.8%	30.3%	21.5%	20.6%	14.9%	1.9%	6.9%	9.3%	10.4%	11.4%	13.7%	14.4%	13.4%	13.3%	14.4%
EBITDA Companywide	**$60**	**$16**	**$117**	**$258**	**$183**	**$24**	**($8)**	**($5)**	**$1**	**$12**	**$1**	**$6**	**$8**	**$6**	**$22**	**$33**
Total EBITDA Margin	11.3%	5.4%	16.9%	16.9%	14.1%	8.5%	-9.1%	-4.6%	1.3%	2.1%	1.1%	4.4%	5.9%	4.5%	4.1%	5.8%
Interest Expense	(14)	(16)	(7)	(5)	(3)	(0)	(1)	(1)	0	(2)	0	0	0	0	0	0
Other Income (expense)	1	1	(3)	1	(15)	(0)	(5)	(1)	(1)	(8)	0	0	0	0	0	0
Income Taxes	($8)	($76)	$1	($2)	($2)	$0	$0	$0	($0)	$0	$1	$1	$0	$0	$2	($0)
Tax Rate	*-14%*	*-79%*	*-2%*	*2%*	*3%*	*-5%*	*0%*	*-1%*	*-1%*	*0%*	*3%*	*3%*	*3%*	*3%*	*3%*	*-1%*
Net Income	**($79)**	**($1)**	**$1**	**$52**	**$4**	**($291)**	**($53)**	**($36)**	**($24)**	**($404)**	**($21)**	**($16)**	**($13)**	**($15)**	**($66)**	**($46)**
Diluted Shares (Avg)		58	72	108	105	102	101	101	101	101	101	101	101	101	101	101
EPS (Adjusted, Diluted)			**$0.42**	**$0.97**	**$0.55**	**($0.03)**	**($0.35)**	**($0.30)**	**($0.23)**	**($0.91)**	**($0.21)**	**($0.16)**	**($0.13)**	**($0.15)**	**($0.65)**	**($0.45)**
Dividend per Share			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	102	19	(80)	7	40	28	71	26	3	129	10	(3)	0	5	13	(2)
Cash from Operations	**$152**	**$5**	**($3)**	**$232**	**$204**	**$47**	**$56**	**$17**	**$4**	**$123**	**$12**	**$4**	**$9**	**$11**	**$36**	**$30**
Capital Expenditures	($54)	($36)	($99)	($165)	($110)	($11)	($5)	($3)	($4)	($23)	($6)	($6)	($6)	($6)	($23)	($18)
Cash from Investing	**($39)**	**($27)**	**($157)**	**($168)**	**($77)**	**($5)**	**$0**	**$2**	**$1**	**($2)**	**($3)**	**($3)**	**($3)**	**($3)**	**($13)**	**($8)**
Increase (decrease) in Debt	($103)	($275)	($5)	($32)	($46)	$0	($0)	($0)	$0	($0)	$0	$0	$0	$0	$0	$0
Cash from Financing	**($107)**	**$46**	**$122**	**($49)**	**($65)**	**($6)**	**($4)**	**($0)**	**$0**	**($11)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	**$16**	**$40**	**$3**	**$17**	**$79**	**$114**	**$166**	**$185**	**$190**	**$190**	**$199**	**$199**	**$205**	**$213**	**$213**	**$236**
Balance Sheet ($ in millions)																
Total Assets	**$650**	**$405**	**$1,356**	**$1,361**	**$1,348**	**$1,027**	**$911**	**$881**	**$861**	**$861**	**$839**	**$825**	**$814**	**$795**	**$795**	**$748**
Long-term Debt, Net of Current	**245**	**0**	**75**	**45**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Stockholder Equity	328	335	1,063	1,111	1,113	816	760	725	702	702	681	664	651	636	636	590
Cash Flow Metrics																
Free Cash Flow	**$98**	**($31)**	**($102)**	**$67**	**$94**	**$35**	**$51**	**$14**	**($0)**	**$101**	**$6**	**($2)**	**$3**	**$5**	**$13**	**$13**
FCF/share (diluted)	$0.00	($0.53)	($1.42)	$0.62	$0.90	$0.35	$0.50	$0.14	($0.00)	$0.99	$0.06	($0.02)	$0.03	$0.05	$0.13	$0.12
Operating Free Cash Flow	**$218**	**($178)**	**($292)**	**$122**	**$128**	**$39**	**$99**	**$10**	**($1)**	**$148**	**$11**	**($3)**	**$2**	**$7**	**$18**	**$11**
Balance Sheet Metrics																
Book Value (per share)	-	$5.73	$14.85	$10.30	$10.63	$7.97	$7.51	$7.18	$6.94	$6.92	$6.73	$6.57	$6.43	$6.28	$6.28	$5.82
Net Debt	**$251**	**($40)**	**$72**	**$28**	**($79)**	**($114)**	**($166)**	**($185)**	**($190)**	**($190)**	**($199)**	**($199)**	**($205)**	**($213)**	**($213)**	**($236)**
Total Debt/Capital	45.0%	0.0%	6.6%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Net Debt/Capital	30.3%	-15.7%	6.0%	2.4%	-8.3%	-19.4%	-39.0%	-52.3%	-59.0%	-59.0%	-70.3%	-74.9%	-85.2%	-101.3%	-101.3%	-197.4%
Return on equity		-52.0%	5.9%	9.6%	5.2%	-1.4%	-17.8%	-16.1%	-13.2%	-10.1%	-12.3%	-9.7%	-8.1%	-9.3%	-9.9%	-7.4%
Return on capital (Net Debt)		**-32.8%**	**6.7%**	**9.6%**	**5.5%**	**-1.4%**	**-21.4%**	**-20.5%**	**-17.9%**	**-11.7%**	**-17.1%**	**-13.8%**	**-11.8%**	**-13.8%**	**-14.1%**	**-11.7%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

TechnipFMC PLC (FTI)

The Year Ahead for FTI

For now, all discussions on FTI begin and end with the purgatorial spin, a constant weight on TechnipFMC shares for a year now, exacerbated by its shelving at the onset of the pandemic. With no more stated barriers, we see several reasonable paths to outcomes that prove far better than those the bears fear regarding capital structures and shareholder return. FTI's increased transparency regarding its well-established new energy positioning also creates the potential for a more creative outcome to capture value by giving the market what it has been craving in 2020. A more periphery catalyst in 2021 involves Subsea hurdling the two recently lowered bars of flat inbound and pressured margins; we think both are achievable and will be cleared up with official guidance alongside 4Q20 results. We remain above Street estimates (+10%/+5% on 2021/2022 EBITDA), and don't view FTI trading at ~4x our normalized EBITDA estimate to be sustainable post-spin resolution.

Things to Focus On in 2021

- **Perpetually-pending spin seems to be staring at a green light.** We think FTI's stated gating items to executing the spin from the beginning of the pandemic are no more, and the "begs the question" situation has led the market to assume the worst. With several less dire outs, we think the stock's underperformance in 2020 creates an upcoming catalyst for the shares, as the accounting complexity overhang vanishes along with clarified (and less scary) capital structures. Given FTI provided more transparency around its new energy capabilities, a natural outcome could be a deal that capitalizes on multiple arbitrage between "brown" and "green" energy with a "controlled spin" (e.g., AKSO's nearly doubling its market cap with its carbon capture and offshore wind spins).
- **Subsea bar unnecessarily lowered once again in our view.** It looks like FTI will hit (or surpass) the $4bn order bogey for 2020 which was made amid peak pandemic uncertainty. While lumpiness is a staple of subsea inbound, FTI provided a rough cut of relatively flat orders in 2021 on the 3Q20 call; we think this is appropriately conservative and matches management's style but the market viewed the "guide" negatively. Investors seem to have also lowered the bar on margin progression in 2021 for the same reason. Subsea projects have not been immune to COVID-19-led delays but the most economic projects will continue to reach FID and we consider FTI to be in an advantaged position to take a bigger slice of the pie (as has been the case in 2020). While still early days, FTI's plans to electrify subsea infrastructure should help inbound and the newly revealed Deep Purple initiative provides RemainCo with a "green option" of its own.
- **Technip Energies further solidifying its central role in the evolving energy mix.** As Yamal continues to wind down with Arctic 2 contributing an increasing mix, we expect Technip Energies margins to move ~140bps lower in 2021 to 9.4% and then 8% in 2022. On the award front, Costa Azul (+$1bn) recently reached FID while XOM is looking to negotiate terms on Rovuma potentially pushing sanctioning beyond 2021 (awarded but not in backlog). Execution on pending Qatar LNG will be key (nearly 2x Rovuma) and we expect a ~$1bn inbound in 1Q21. We think 2021 will be important for FTI to show investors the efficacy of its new energy exposures with the potential to be rewarded by the market via a partial monetization far above its current (very) "brown" multiple.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 40: TechnipFMC PLC Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue ($, millions)																
Subsea	$11,029	$9,171	$5,877	$4,840	$5,523	$1,253	$1,379	$1,502	$1,418	$5,552	$1,341	$1,300	$1,252	$1,183	$5,076	$5,284
Technip Energies	7,029	6,384	7,905	6,121	6,269	1,548	1,538	1,608	1,861	6,555	1,440	1,624	1,701	1,989	6,753	6,934
Surface Technologies	1,883	1,252	1,275	1,592	1,617	330	242	226	242	1,039	234	239	243	239	954	1,015
Total Revenue Companywide	**$19,912**	**$16,783**	**$15,057**	**$12,553**	**$13,409**	**$3,130**	**$3,159**	**$3,336**	**$3,521**	**$13,146**	**$3,015**	**$3,162**	**$3,196**	**$3,410**	**$12,783**	**$13,233**
Total Costs & Expenses	($18,847)	($15,526)	($13,526)	($11,016)	($11,880)	($2,910)	($2,917)	($3,015)	($3,292)	($12,134)	($2,845)	($2,988)	($3,019)	($3,216)	($12,069)	($12,521)
Total D&A	($591)	($503)	($467)	($459)	($476)	($112)	($107)	($109)	($109)	($436)	($109)	($109)	($109)	($109)	($434)	($434)
EBITDA	**$2,353**	**$2,128**	**$1,988**	**$1,537**	**$1,529**	**$220**	**$241**	**$321**	**$338**	**$1,120**	**$278**	**$282**	**$286**	**$303**	**$1,149**	**$1,146**
Total Operating Income Companywide	**$1,789**	**$1,244**	**$1,521**	**$1,078**	**$1,054**	**$108**	**$135**	**$213**	**$229**	**$685**	**$169**	**$174**	**$177**	**$194**	**$715**	**$712**
Subsea Margins	14.7%	13.7%	12.8%	7.3%	6.1%	2.5%	1.5%	4.2%	3.5%	3.0%	3.1%	3.5%	3.8%	4.3%	3.7%	4.8%
Technip Energies Margins	3.4%	5.9%	10.6%	12.9%	16.0%	10.2%	10.0%	10.3%	10.5%	10.3%	10.1%	9.0%	8.6%	8.1%	8.8%	7.5%
Surface & Energy Infrastructure Margins	9.5%	0.6%	13.2%	12.2%	4.3%	0.1%	-2.8%	0.8%	1.5%	-0.1%	0.9%	1.2%	1.6%	1.2%	1.2%	2.4%
Total Operating Margins	**9.0%**	**7.4%**	**10.1%**	**8.6%**	**7.9%**	**3.5%**	**4.3%**	**6.4%**	**6.5%**	**5.2%**	**5.6%**	**5.5%**	**5.5%**	**5.7%**	**5.6%**	**5.4%**
Income Taxes	($278)	($307)	($621)	($342)	($327)	($75)	($14)	($38)	($31)	($158)	($29)	($32)	($34)	($39)	($134)	($138)
Tax Rate	*17%*	*27%*	*54%*	*48%*	*54%*	*208%*	*24%*	*32%*	*25%*	*47%*	*29%*	*29%*	*29%*	*29%*	*29%*	*29%*
Net Income	**$1,203**	**$737**	**$374**	**($1,904)**	**($2,274)**	**($3,256)**	**$12**	**($4)**	**$92**	**($3,157)**	**$73**	**$80**	**$85**	**$97**	**$336**	**$337**
Diluted Shares (Avg)	506	498	468	460	451	448	450	449	449	449	449	449	449	449	449	449
EPS (Adjusted, diluted)	**$2.64**	**$1.70**	**$1.10**	**$0.78**	**$0.60**	**($0.11)**	**$0.09**	**$0.16**	**$0.20**	**$0.35**	**$0.16**	**$0.18**	**$0.19**	**$0.22**	**$0.75**	**$0.75**
Additional Information																
Subsea ($ in millions)																
Backlog	11,766	7,289	6,203	6,000	8,480	7,774	7,085	7,218	6,894	6,894	6,584	6,316	6,095	6,274	6,274	7,292
Orders	6,556	4,041	5,144	5,179	7,993	1,172	512	1,607	744	4,035	1,031	1,031	1,031	1,031	4,125	5,500
Book-to-Bill Ratio	0.59x	0.44x	0.88x	1.07x	1.45x	0.94x	0.37x	1.07x	0.52x	0.73x	0.77x	0.79x	0.82x	0.87x	0.81x	1.04x
Technip Energies ($ in millions)																
Backlog	10,579	12,188	6,369	8,091	15,298	13,767	13,133	12,059	13,621	13,621	13,986	13,620	13,291	12,346	12,346	11,610
Orders	4,926	3,678	3,813	7,426	13,081	561	836	413	3,423	5,232	1,640	1,143	1,143	1,044	4,971	5,219
Book-to-Bill Ratio	0.70x	0.58x	0.48x	1.21x	2.09x	0.36x	0.54x	0.26x	1.84x	0.80x	1.14x	0.70x	0.67x	0.52x	0.74x	0.75x
Surface ($ in millions)																
Backlog	597	409	410	470	473	422	386	369	345	345	333	321	309	297	297	246
Orders	1,669	1,068	1,240	1,687	1,620	366	187	208	218	979	222	227	231	227	907	964
Book-to-Bill Ratio	0.89x	0.85x	0.97x	1.06x	1.00x	1.11x	0.77x	0.92x	0.90x	0.94x	0.95x	0.95x	0.95x	0.95x	0.95x	0.95x
Cash Flow Statement ($ in millions)																
Cash from Operations			**43**	**(185)**	**849**	**28**	**(94)**	**168**	**330**	**432**	**57**	**85**	**206**	**224**	**572**	**668**
Capital expenditures			($256)	($368)	($454)	($84)	($94)	($73)	($56)	($307)	($60)	($63)	($64)	($68)	($256)	($291)
Cash from Investing			**$1,250**	**($460)**	**($420)**	**($74)**	**($64)**	**($75)**	**($57)**	**($269)**	**($60)**	**($63)**	**($64)**	**($68)**	**($256)**	**($291)**
Increase (decrease) in LT Debt			($734)	($4)	$96	$0	$164	($364)	$0	($201)	$0	$0	$0	$0	$0	$0
Cash from Financing			**($1,055)**	**($445)**	**($784)**	**$1**	**($130)**	**($783)**	**($100)**	**($1,012)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period			**$6,737**	**$5,540**	**$5,190**	**$4,999**	**$4,810**	**$4,244**	**$4,542**	**$4,542**	**$4,664**	**$4,810**	**$5,077**	**$5,358**	**$5,358**	**$6,234**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (Net)		3,883	3,872	3,260	3,162	2,853	2,851	2,806	2,739	2,739	2,676	2,616	2,556	2,501	2,501	2,298
Total Assets		**$30,551**	**$28,571**	**$25,004**	**$23,450**	**$19,928**	**$19,594**	**$18,911**	**$18,963**	**$18,963**	**$18,637**	**$18,874**	**$19,002**	**$19,390**	**$19,390**	**$21,101**
Long-term Debt, Net of Current		**$2,567**	**$3,778**	**$4,124**	**$3,980**	**$3,824**	**$3,983**	**$3,248**	**$3,248**	**$3,248**	**$3,248**	**$3,248**	**$3,248**	**$3,248**	**$3,248**	**$3,248**
Stockholder Equity		$13,247	$13,409	$10,469	$7,729	$4,124	$4,217	$4,276	$4,468	$4,468	$4,759	$5,051	$5,288	$5,537	$5,537	$6,487
Cash Flow Metrics																
Free Cash Flow		**$749**	**($213)**	**($554)**	**$394**	**($56)**	**($188)**	**$95**	**$274**	**$125**	**($3)**	**$22**	**$142**	**$156**	**$317**	**$377**
FCF/share (diluted)		$1.50	($0.46)	($1.20)	$0.87	($0.12)	($0.42)	$0.21	$0.61	$0.28	($0.01)	$0.05	$0.32	$0.35	$0.70	$0.84
Balance Sheet Metrics																
Book Value (per share)		$26.59	$28.63	$22.78	$17.14	$9.22	$9.38	$9.51	$9.94	$9.95	$10.59	$11.24	$11.77	$12.32	$12.32	$14.43
Net Debt		**($3,523)**	**($2,882)**	**($1,348)**	**($715)**	**($589)**	**($303)**	**($384)**	**($682)**	**($682)**	**($804)**	**($950)**	**($1,217)**	**($1,498)**	**($1,497)**	**($2,374)**
Total Debt/Capital		22.2%	22.3%	28.6%	36.7%	51.7%	51.7%	47.4%	46.4%	46.4%	44.8%	43.3%	42.2%	41.1%	41.1%	37.3%
Net Debt/Capital		-36.2%	-27.4%	-14.8%	-10.2%	-16.7%	-7.7%	-9.9%	-18.0%	-18.0%	-20.3%	-23.2%	-29.9%	-37.1%	-37.1%	-57.7%
Return on equity		6.4%	3.8%	3.4%	3.5%	-3.3%	4.0%	6.8%	8.4%	3.5%	6.3%	6.6%	6.6%	7.1%	6.1%	5.2%
Return on capital (Net Debt)		**4.1%**	**3.0%**	**2.3%**	**2.0%**	**-1.7%**	**1.5%**	**2.6%**	**3.6%**	**1.5%**	**3.4%**	**3.7%**	**4.0%**	**4.4%**	**3.8%**	**3.4%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Tenaris (TS)

The Year Ahead for TS

Tenaris looks to be in a relatively advantaged position as it emerges from the downturn in 2021 with a best-in-class balance sheet and confidence in FCF given its reinstated interim dividend of $0.14/ADR. The competitive structure of its most important end market (NAM) is improving with IPSCO fully consolidated (and customers returning) while competitors pull back the reins. With a surprisingly strong ~13% margin in 3Q we expect improved cost absorption and the lapping of 2020's cost-out to help margins continue to progress (with higher material costs being passed through to pricing). Still, top line risks remain given the pace of recovery in 2021/2022 could underwhelm, both internationally and in NAM. While "new energy" is still very small for TS (some CCS/geothermal, hydrogen and EV exposure), the energy transition may become a larger part of the story sooner than later (despite meaningful volume not there yet). All that said, we think the shares have come to appreciate these points with the shares considerably higher following the strong 3Q print (+63% since 11/4 v. +58% OSX). Despite being higher than the Street in 2021 (a rarity), a ~5% "normalized" FCF yield on EV looks fairly well priced in our view even with TS's higher quality characteristics v. OFS peers.

Things to Focus On in 2021

- **Market structure improving but pace of recovery in question.** With North American activity falling off a cliff this year, OCTG pricing was hit hard, declining ~12% YTD according to Pipe Logix. The most recent readings have stabilized (if still down ~16% y/y), and margins still face headwinds as higher input prices work their way through contracting. The oversupplied market is in the early innings of a recovery, helped by lower imports, meager utilization and ongoing OCTG supply rationalization. Given our conservative expectation of the pace of activity advancing in NAM and abroad, we expect stabilizing pricing in 2021 (+2% y/y) thanks to q/q gains in volumes (if still down -8% y/y).

- **Margins and 2021 expectations have rebased higher.** After the 3Q20 bar was materially lowered (on account for macro uncertainty), TS printed better-than-expected top line, but the true surprise was on margin (+950 bps v. Street). While the results appeared to surprise everyone on the Street (including management), we think the results have staying power given cost absorption benefits on improving revenue (from 3Q's trough) and lapping 2020's cost-out execution with some room for incremental savings and downside risk stemming from how 2021 activity unfolds.

- **Wringing out the cash rag (again) in 2021 is key.** With a strong ~$1.4bn in free cash flow generated in 2020 boosted by ~$1.2bn in working capital release, we're focusing on normalized FCF potential in the coming cycle. We expect WC to be about neutral in 2021 with improved capital efficiency (capex/sales of 3.4% v. ~10% '15-'19) resulting in FCF of $385mm. This compares to our normalized estimate of $420mm, keeping us on the sideline for now on an FCF/EV basis (~5% yield) after the stock's strong post-3Q/U.S. election run.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 41: Tenaris Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Tubes Revenue	6,444	4,015	4,967	7,233	6,870	1,657	1,190	946	1,012	4,805	1,050	1,080	1,123	1,144	4,398	4,739
Other Revenue	657	457	322	426	424	105	51	66	70	292	72	74	76	79	301	328
Total Revenue	**$7,101**	**$4,472**	**$5,289**	**$7,659**	**$7,294**	**$1,762**	**$1,241**	**$1,013**	**$1,081**	**$5,097**	**$1,122**	**$1,154**	**$1,199**	**$1,223**	**$4,699**	**$5,067**
COGS	(4,885)	(3,266)	(3,685)	(5,279)	(5,107)	(1,294)	(1,042)	(856)	(861)	(4,053)	(891)	(908)	(933)	(947)	(3,679)	(3,889)
SG&A	(1,624)	(1,221)	(1,270)	(1,510)	(1,356)	(322)	(232)	(206)	(205)	(966)	(202)	(208)	(216)	(220)	(846)	(912)
Total Costs & Expenses	**($6,905)**	**($4,478)**	**($4,954)**	**($6,787)**	**($6,452)**	**($1,614)**	**($1,278)**	**($1,055)**	**($1,066)**	**($5,014)**	**($1,093)**	**($1,116)**	**($1,149)**	**($1,167)**	**($4,525)**	**($4,801)**
Total D&A	(659)	(662)	(609)	(664)	(539)	(155)	(149)	(178)	(151)	(633)	(152)	(152)	(153)	(154)	(611)	(624)
EBITDA																
EBITDA Companywide	**$854**	**$657**	**$943**	**$1,536**	**$1,382**	**$303**	**$113**	**$135**	**$166**	**$716**	**$181**	**$190**	**$203**	**$210**	**$785**	**$890**
Interest Expense	(23)	(22)	(27)	(37)	(43)	(8)	(7)	(7)	(6)	(29)	(5)	(5)	(5)	(5)	(22)	(21)
Other Financial Results	(37)	50	73	228	97	(14)	(5)	8	8	(4)	0	0	0	0	0	0
Income Taxes	(245)	(37)	17	(229)	(202)	(25)	49	28	(4)	49	(5)	(7)	(9)	(10)	(32)	(51)
Tax Rate	*144%*	*42%*	*-4%*	*21%*	*21%*	*19%*	*108%*	*78%*	*20%*	*-73%*	*18%*	*18%*	*18%*	*18%*	*18%*	*18%*
Net Income	**-$113**	**$55**	**$545**	**$870**	**$745**	**-$660**	**-$48**	**-$33**	**$17**	**-$724**	**$24**	**$31**	**$42**	**$47**	**$145**	**$233**
Diluted Shares (Avg)	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590	590
EPS (Adjusted, Diluted)	**($0.18)**	**$0.10**	**$0.91**	**$1.48**	**$1.26**	**$0.17**	**$0.01**	**($0.01)**	**$0.03**	**$0.20**	**$0.04**	**$0.05**	**$0.07**	**$0.08**	**$0.25**	**$0.40**
Dividend per Share	$0.90	$0.86	$0.82	$0.82	$0.82	$0.00	$0.00	$0.00	$0.14	$0.14	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	1,374	348	(855)	(772)	523	317	446	334	103	1,201	43	50	(38)	(44)	10	(231)
Cash from Operations	**$2,215**	**$864**	**($22)**	**$611**	**$1,528**	**$516**	**$448**	**$417**	**$186**	**$1,567**	**$154**	**$169**	**$112**	**$112**	**$547**	**$626**
Capital Expenditures	(1,132)	(787)	(558)	(349)	(350)	(68)	(46)	(42)	(40)	(195)	(40)	(39)	(42)	(41)	(162)	(178)
Cash from Investing	**($1,774)**	**($98)**	**$349**	**$399**	**($40)**	**($1,101)**	**($331)**	**($300)**	**($40)**	**($1,771)**	**($40)**	**($39)**	**($42)**	**($41)**	**($162)**	**($178)**
Cash Flow from Borrowing Activities	0	(115)	107	(413)	142	(95)	(34)	(11)	0	(140)	0	0	0	0	0	0
Cash from Financing	**($535)**	**($653)**	**($401)**	**($900)**	**($354)**	**($110)**	**($44)**	**($22)**	**($83)**	**($258)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash at End of Period	286	399	330	427	1,554	841	911	1,005	1,069	1,069	1,182	1,312	1,382	1,454	1,454	1,902
Balance Sheet ($ in millions)																
Total Assets	**$14,887**	**$14,003**	**$14,398**	**$14,251**	**$14,843**	**$14,121**	**$13,896**	**$13,862**	**$13,703**	**$13,703**	**$13,683**	**$13,653**	**$13,666**	**$13,674**	**$13,674**	**$13,916**
Long-term Debt, Net of Current	**$223**	**$32**	**$35**	**$29**	**$41**	**$175**	**$232**	**$304**	**$304**	**$304**	**$304**	**$304**	**$304**	**$304**	**$304**	**$304**
Stockholder Equity	11,866	11,413	11,581	11,875	12,186	11,414	11,377	11,367	11,272	11,272	11,276	11,288	11,330	11,377	11,377	11,610
Cash Flow Metrics																
Free Cash Flow	**$1,083**	**$77**	**($580)**	**$261**	**$1,178**	**$448**	**$402**	**$376**	**$147**	**$1,372**	**$114**	**$129**	**$71**	**$71**	**$385**	**$448**
FCF/share (diluted)	$1.8	$0.1	($1.0)	$0.4	$2.0	$0.8	$0.7	$0.6	$0.2	$2.3	$0.2	$0.2	$0.1	$0.1	$0.7	$0.8
FCF Yield	6.6%	0.5%	-3.2%	1.4%	16.7%	25.4%	22.8%	21.3%	8.3%	19.4%	6.4%	7.3%	4.0%	4.0%	5.4%	6.3%
Operating Free Cash Flow	**$892**	**$324**	**($495)**	**$184**	**$727**	**$32**	**($267)**	**($251)**	**$12**	**($473)**	**$88**	**$89**	**$185**	**$198**	**$560**	**$872**
Balance Sheet Metrics																
Book Value (per share)	20	19	20	20	21	19	19	19	19	19	19	19	19	19	19	20
Net Debt	**$685**	**$440**	**$636**	**$111**	**($732)**	**($143)**	**($212)**	**($300)**	**($363)**	**($363)**	**($477)**	**($606)**	**($677)**	**($748)**	**($748)**	**($1,196)**
Total Debt/Capital	7.6%	6.9%	7.7%	4.3%	6.3%	5.8%	5.8%	5.8%	5.9%	5.9%	5.9%	5.9%	5.9%	5.8%	5.8%	5.7%
Net Debt/Capital	5.5%	3.7%	5.2%	0.9%	-6.4%	-1.3%	-1.9%	-2.7%	-3.3%	-3.3%	-4.4%	-5.7%	-6.4%	-7.0%	-7.0%	-11.5%
Return on equity	-0.9%	0.5%	4.7%	7.5%	6.2%	3.5%	0.1%	-0.3%	0.6%	1.0%	0.9%	1.1%	1.5%	1.7%	1.3%	2.0%
Return on capital (Net Debt)	**-0.9%**	**0.6%**	**4.7%**	**7.5%**	**6.6%**	**3.8%**	**0.1%**	**-0.2%**	**0.8%**	**1.5%**	**1.1%**	**1.3%**	**1.7%**	**1.9%**	**1.5%**	**2.4%**

Source: Company reports and J.P. Morgan estimates.

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Transocean (RIG)

The Year Ahead for RIG

Transocean has navigated the tumultuous waters of this downturn quite well compared to its peers, which was especially apparent in 2020 on the operational and financial front(s). RIG was able to keep rigs working and avoid cancelations (exhibiting its strong relationships and contract terms), while achieving strong efficiency metrics and managing opex better than many expected. Still, it has long been our view that the slope and duration of the offshore cycle would prove insufficient to allow the company to generate enough cash to address its looming maturity wall in 2023 (and sticky newbuild commitments). By no means did we expect a global pandemic to be the catalyst for RIG to initiate a liability management exercise, but seeing nearly the entire industry sits in some form of restructuring has long been inevitable to us. While the process has put RIG's financial wherewithal on full display and (to a degree) helped extend its liquidity runway, we think restructuring risk in 2021 is on the rise given our offshore market outlook, strategic considerations (considering the status of the majority of the offshore fleet mid-restructuring), and the potential for insufficient access to capital.

Things to Focus On in 2021

- **Navigating the liability management roadmap.** RIG's equity was down ~70% at one point following its uptier exchange announcement on 8/5, but has rallied ~270% since its bottom on 10/30. Assuming its legal complexities are resolved and don't hurt liquidity further, our high yield credit colleagues think RIG has the financial wherewithal to potentially to make it to 2022/2023. With our outlook, we note that restructuring risk is still relevant in 2021 as the duration of the downturn could extend beyond current expectations (once again), potentially dispelling access to capital.

- **Contrast between contracting capabilities and company commentary remains stark.** Drillship market dynamics are a key lever but RIG's premium bidding strategy looks to us to be a disadvantage. We think the *Asgard* will struggle to secure work (even in S. America) and the *Orion* remains uncontracted after recently bidding considerably higher in a PBR tender. Semi scrapping/stacking has been constructive this year but plenty of white space remains. Apart from the rigs on long term contracts with EQNR, backlog coverage into 2021 looks weak. RIG seems to have decent line of sight for the *Norge, Nautilus* and *DD3* but work will still be biased to be put on hold in our view. It also remains to be seen if the *Barents* can find its way into the stimulus-supported Norway market. Overall, we expect more additional prudent stacking decisions by RIG in 2021, dictated by market realities.

- **Efficiency remains strong but sustainability of opex management in question.** RIG's assets continue to display strong efficiency, especially when considering the COVID-19 disruptions across the global fleet. In 3Q, RIG guided to a $500mm y/y decrease in contract drilling expense (-25% y/y on a ~15% decline in revenue). Given limited granularity (i.e. no cost-out initiative announced) it's difficult to parse out the activity v. structural components of this cost structure improvement, leaving room for disappointment for a meaningful improvement in contracting activity (which we see as a +2022 story).

Sean C Meakim, CFA
(1-212) 622-6684
sean.meakim@jpmorgan.com

Table 42: Transocean Financial Model

	2015	2016	2017	2018	2019	1Q20	2Q20	3Q20	4Q20e	2020e	1Q21e	2Q21e	3Q21e	4Q21e	2021e	2022e
Income Statement ($ in millions)																
Revenue																
Ultra Deepwater Floaters	$3,366	$2,317	$1,917	$1,750	$1,958	$528	$459	$490	$414	$1,891	$385	$350	$334	$426	$1,495	$1,527
Deepwater Floaters	644	214	143	124	8	0	0	0	0	0	0	0	0	0	0	0
Harsh Environment Floaters	891	484	437	974	1,068	220	272	283	255	1,030	221	211	190	233	856	848
Midwater Floaters	1,359	388	66	74	54	11	1	0	0	12	0	0	0	0	0	0
High Spec Jackups	526	288	168	59	0	0	0	0	0	0	0	0	0	0	0	0
Total Contract Drilling	$6,802	$3,705	$2,731	$2,828	$3,088	$759	$732	$773	$668	$2,932	$607	$562	$525	$659	$2,352	$2,375
Total Revenue Companywide	**$7,019**	**$3,992**	**$2,771**	**$3,018**	**$3,230**	**$807**	**$785**	**$830**	**$725**	**$3,147**	**$664**	**$620**	**$582**	**$707**	**$2,572**	**$2,491**
COGS	($3,743)	($1,905)	($1,407)	($1,799)	($2,140)	($540)	($525)	($470)	($445)	($1,980)	($412)	($369)	($373)	($380)	($1,534)	($1,550)
SG&A	(171)	(160)	(150)	(154)	(196)	(32)	(40)	(40)	(42)	(154)	(40)	(37)	(35)	(42)	(154)	(149)
Total Costs & Expenses	**($3,914)**	**($2,065)**	**($1,557)**	**($1,953)**	**($2,336)**	**($572)**	**($565)**	**($492)**	**($487)**	**($2,116)**	**($452)**	**($406)**	**($408)**	**($422)**	**($1,688)**	**($1,699)**
Total D&A	($963)	($868)	($832)	($818)	($855)	($206)	($196)	($190)	($186)	($778)	($182)	($179)	($179)	($179)	($719)	($715)
EBITDA	**$3,105**	**$1,927**	**$1,214**	**$1,065**	**$934**	**$235**	**$220**	**$338**	**$238**	**$1,031**	**$211**	**$214**	**$174**	**$285**	**$884**	**$792**
Total Operating Income Companywide	**$2,142**	**$1,059**	**$382**	**$247**	**($16)**	**$29**	**$24**	**$148**	**$52**	**$253**	**$29**	**$35**	**($5)**	**$106**	**$165**	**$77**
Income Taxes	($378)	($152)	($89)	($85)	($209)	($15)	($22)	($21)	($12)	($70)	($25)	($23)	($33)	($5)	($86)	($105)
Net Income	**$423**	**$621**	**($3,180)**	**($2,021)**	**($1,255)**	**($392)**	**($497)**	**$359**	**($89)**	**($345)**	**($123)**	**($116)**	**($166)**	**($23)**	**($428)**	**($525)**
Diluted Shares (Avg)	364	371	391	468	612	614	615	702	616	616	616	616	616	616	616	616
EPS (Adjusted, Diluted)	**$3.77**	**$1.29**	**($0.45)**	**($0.79)**	**($1.45)**	**($0.30)**	**($0.00)**	**($0.10)**	**($0.15)**	**($0.55)**	**($0.20)**	**($0.19)**	**($0.27)**	**($0.04)**	**($0.70)**	**($0.85)**
Dividend per Share	$1.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cash Flow Statement ($ in millions)																
Total Working Capital Changes	(364)	203	(19)	129	(311)	(167)	(181)	(136)	75	(409)	125	108	70	(175)	128	15
Cash from Operations	**$3,445**	**$1,911**	**$1,144**	**$558**	**$340**	**($48)**	**$87**	**$81**	**$172**	**$292**	**$184**	**$172**	**$83**	**($19)**	**$419**	**$206**
Capital expenditures	($2,001)	($1,344)	($497)	($184)	($387)	($107)	($46)	($65)	($55)	($273)	($409)	($409)	($342)	($342)	($1,500)	($263)
Cash at End of Period	**$2,339**	**$3,052**	**$2,519**	**$2,133**	**$1,893**	**$1,558**	**$1,511**	**$1,382**	**$1,285**	**$1,277**	**$1,052**	**$815**	**$856**	**$574**	**$574**	**$894**
Balance Sheet ($ in millions)																
Property, Plant, & Equip. (Net)	20,818	21,093	17,402	20,408	18,847	18,580	18,009	17,831	17,700	17,700	17,926	18,155	18,318	18,481	18,481	18,029
Total Assets	**$26,379**	**$26,778**	**$22,410**	**$25,665**	**$24,105**	**$23,451**	**$22,825**	**$22,472**	**$22,100**	**$22,100**	**$21,905**	**$21,711**	**$21,790**	**$21,813**	**$21,813**	**$21,543**
Long-term Debt, Net of Current	**7,397**	**7,740**	**7,146**	**9,605**	**8,693**	**8,576**	**8,480**	**7,794**	**7,794**	**7,794**	**7,572**	**7,572**	**7,272**	**6,972**	**6,972**	**6,372**
Stockholder Equity	14,855	16,547	12,769	13,114	11,867	11,475	10,987	11,403	11,248	11,248	11,068	10,894	10,971	11,200	11,200	11,159
Cash Flow Metrics																
Free Cash Flow	**$1,444**	**$567**	**$647**	**$374**	**($47)**	**($155)**	**$41**	**$16**	**$117**	**$19**	**($225)**	**($237)**	**($259)**	**($360)**	**($1,081)**	**($57)**
FCF/share (diluted)	$3.97	$1.53	$1.66	$0.80	($0.08)	($0.16)	$0.07	($0.11)	$0.19	$0.03	($0.08)	($0.38)	($0.98)	($0.59)	($1.75)	($0.09)
Operating Free Cash Flow	**$384**	**$654**	**$652**	**$978**	**$70**	**($45)**	**($25)**	**$122**	**$253**	**$305**	**($91)**	**($103)**	**($125)**	**($230)**	**($550)**	**$463**
Balance Sheet Metrics																
Book Value (per share)	$41	$45	$33	$28	$19	$19	$27	$26	$25	$18	$18	$27	$26	$25	$18	$18
Net Debt	**$6,151**	**$5,387**	**$4,427**	**$7,818**	**$7,471**	**$7,674**	**$7,547**	**$7,052**	**$6,943**	**$6,943**	**$7,168**	**$7,405**	**$7,364**	**$7,424**	**$7,424**	**$6,882**
Total Debt/Capital	36.4%	33.8%	36.7%	43.2%	43.8%	44.4%	45.2%	42.5%	42.2%	42.2%	42.6%	43.0%	42.9%	41.7%	41.7%	41.1%
Net Debt/Capital	29.3%	24.6%	25.7%	37.3%	38.6%	40.1%	40.7%	38.2%	38.2%	38.2%	39.3%	40.5%	40.2%	39.9%	39.9%	38.1%
Return on equity	9.6%	3.4%	-1.1%	-11.6%	-28.5%	-6.4%	0.0%	-2.5%	-3.2%	-11.9%	-4.4%	-4.2%	-6.1%	-0.8%	-15.3%	-18.8%
Return on capital (Net Debt)	**8.1%**	**3.9%**	**4.8%**	**8.9%**	**-0.5%**	**-0.2%**	**-0.2%**	**3.0%**	**1.5%**	**8.5%**	**1.0%**	**1.1%**	**0.0%**	**3.0%**	**5.1%**	**2.7%**

Source: Company reports and J.P. Morgan estimates.

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