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Dear Frac Bears: Efficiency Gains Are Far From Tapped Out - The RigLock Boost To Pressure Pumping EBITDA

Top Tier pressure pumpers leaning more on efficiency to drive incremental growth, profitability, and returns. Our pressure pumping S/D model predicts that an already effectively-sold out domestic frac market will be *physically short* HHP by the end of 2018 (based on the projected rig count), and as such pricing dynamics remain constructive for the top tier providers. In a NAM oilfield environment where activity growth has steadied (yielding some near-term softness in the service spot market), it is up to the pressure pumpers to push the envelope on additional field-level efficiencies to drive incremental growth and profitability. Marginal pricing increases are welcomed, but tangible stages/day improvements are much more powerful in improving cash flow generation on a per frac spread, per wireline truck, or per pump-down crew basis.

The importance of efficiency: +1 stage/day beats +$5k/stage pricing *any day*. We conjecture that reasonable Permian pricing/operational assumptions include $50-$55k/stage (sand/LML sourcing-dependent) at ~25% gross margin and roughly 4-6 stages/day (completion design-dependent). Moreover, the majority of our coverage currently supports ~$750k in SG&A per spread per quarter. With these round number assumptions in mind, it is not unreasonable to assume that given a consistent 25 working days per month, efficient pressure pumpers can achieve ~$16-20 million in annualized EBITDA/spread. *In the current (estimated) stage pricing regime, an incremental stage/day outweighs a $5k/stage pricing increase until throughput reaches a whopping 9 stages/day.* We would also speculate that such efficiency gains are also rewarded with higher pricing and better backlog visibility, as the E&P also benefits from a quicker-than-expected operation through smaller-than-expected day-rental costs.

RigLock seems to be the 'next best completion tech' of 2018 as adoption gains momentum across key hotbed basins. RigLock is another 'not so new' technology that appears to have made landfall in the Permian (and other key basins) in early 2018, and is quickly gaining adoption among the premier pressure pumping contingency. Simply put, RigLock is a remote-operated wellhead add-on that allows for the quick connect/disconnect of crucial pressure control equipment (PCE) during perforation and stimulation operations. The one-size-fits-all design principally allows both WL and pressure pumping crews to quickly rig up, pressure test, and begin operations through PCE that would otherwise need to be installed manually by personnel suspended at-height (particularly useful in extracting additional efficiency from zipper frac completions). The technology was pioneered by Shell and Renegade Wireline in Appalachia, and has since been manufacturing by FHE. *The majority of our pressure pumping coverage estimates ~20-30 minutes of time savings per well swap, **potentially yielding an incremental 1-2 stages/day** (depending on the basin, customer, and design).*

For an animation of the original FHE's RigLock technology: **click here**

For background on Shell/Renegades RigLock development in Appalachia: **click here**

For reading/specs on GR Energy's analogous ZipLok technology: **click here**

For an overview of FET's QuickConnect iteration of the technology: **click here**

The RigLock Path to an incremental $4-5 million in annualized EBITDA/spread. All else equal, and assuming no additional bottlenecks appear with widespread adoption of RigLock, we simplistically believe the incremental 20-30 minutes between well swaps could yield an incremental 1-2 stages/day. **Our sensitivity attributes this incremental stage to ~$4-5 million in annualized EBITDA per spread, well above the levels needed to comfortably hit the vast majority of our pressure pumping out-year profitability levels.** In our view, enhanced pricing would also accompany the throughput/HSE benefits.

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Pressure Pumping Is At A Critical Growth vs. Returns Crossroads

The "Haves vs. Have Nots" thesis is playing out in a widening EV/HHP spread. Following on our recent note that addressed the continued bifurcation of the pressure pumping market in **A Tale Of Haves And Have Nots**, we are digging deeper into the most recent field-level trends that are driving incremental efficiency gains in U.S. shale (and in particular, driving a pressure pumping efficiency curve that seems to have lagged the rest of OFS value chain). From a macro standpoint, the frac market remains undersupplied relative to the rig count, and it is our view that current and near-term utilization supports a healthy pricing environment for those pumpers that can maintain a baseline level of service quality and reliability. Perhaps more importantly, the equity market is beginning to subscribe to a similar 'bifurcation thesis' (away, albeit modestly, from the view that frac is perfectly commoditized), and this is evident in the disassociation between the "Haves" and "Have Nots" on an EV/HHP basis (vs. the relatively narrow range observed from an EV/EBITDA perspective). In our view, cash flow is king and the rigors of the Shale Revolution are just enough to give differentiated pressure pumpers 1) pricing leverage and 2) share defensibility behind a wall of increasing switching costs and NPT trade-off. LBRT, PUMP and FTSI are among the front-runners poised to deliver significant cash to shareholders over the next several years.

Even if the *Madden ROCE Playbook* says "Build," we hope that the pumpers opt to punt cash back to shareholders. Multiple compression on what we view as conservative consensus EBITDA estimates in '18 and '19 are symptomatic of a lingering fear/apprehension/apathy toward OFS in general, but punishment for the pressure pumpers, specifically, is indicative of the sheer distrust that investors hold toward a subsector that has *always* overbuilt itself into a premature pricing downturn. Rapidly increasing FCF yields underscore the market belief that this unbridled growth will take precedence over cash delivery to shareholders – so why pay more than a few turns of EBITDA when the cash flow will inevitably be destroyed by the pumps when they begin to work below breakeven in the next downturn (unfortunately, E&P goodwill dollars cannot be cut into a dividend check to shareholders, nor can they be held on the balance sheet to offset future costs). In other words, pressure pumping is still an unloved subsector – even within the unloved OFS sector – and the next catalyst for the group is clearly a more solid commitment to returns. Even if the Madden "ROIC/ROCE Playbook" says "build," we hope that the pumpers opt to punt the cash back to shareholders.

Figure 1. Pure Play Pressure Pumping Comps – Per Spread Cash Yield Set To Explode In '18/'19

Peers	Current HHP (000s)	Enterprise Value ($USD)	PP EV	EV/HHP	% HHP Active	EV/Active HHP	2018YE Capacity	EV/2018 YE HHP	EV/2018E EBITDA (EVRISI)	EV/2019E EBITDA (EVRISI)	2018 FCF Yield (EBITDA-Capex)/Mkt Cap	2019 FCF Yield (EBITDA-Capex)/Mkt Cap	2018E EBITDA (EVRISI)	2019E EBITDA (EVRISI)	Maint. Capex ($MM/spread per year)
RES	975,000	$3,947	65%	$2,631	100%	$2,631	1,025,000	$2,503	5.1x	3.5x	7.9%	13.4%	505.0	735.9	$5.5
PUMP	815,000	$1,730	100%	$2,122	100%	$2,122	905,000	$1,911	5.0x	4.1x	13.1%	16.7%	347.1	422.1	$5.3
FRAC	1,189,250	$1,983	100%	$1,667	100%	$1,667	1,339,250	$1,480	5.2x	4.0x	15.3%	21.4%	384.4	500.4	$4.0
LBRT	910,000	$2,739	100%	$3,010	100%	$3,010	1,080,000	$2,536	5.4x	4.3x	16.5%	21.0%	505.3	637.9	$2.5
FTSI	1,375,000	$2,955	100%	$2,149	100%	$2,149	1,700,000	$1,738	4.7x	3.7x	23.4%	29.6%	631.4	789.6	$2.5
Average				**2,316**		**2,316**		**2,034**	**5.1x**	**3.9x**					
Aggregate	5,264,250	13,353	90%	$2,274	100%	2,274	6,049,250	$1,979	5.6x	4.3x					

Source: Company Guidance, Evercore ISI Research

Next Leg Up For Growth, Profitability & Returns? The Multivariate Efficiency Equation

Pricing remains constructive, but Top Tier pressure pumpers leaning more on efficiency to drive incremental growth, profitability, and returns. Our pressure pumping S/D model predicts that an already effectively-sold out domestic frac market will be *physically short* HHP by the end of 2018 (based on the projected rig count), and as such pricing dynamics remain constructive for the top tier providers. However, lack of takeaway capacity, wellhead differentials, rising associated gas production, and other logistical bottlenecks have eased E&P urgency with respect to POP timing; as such, many of the blue-chip producers are happy letting the DUC inventory build as rising oil prices help bring the overarching 'capital austerity' strategy to fruition. In a NAM oilfield environment where activity growth has steadied (yielding some near-term softness in the service spot market), it is up to the pressure pumpers to push the envelope on additional field-level efficiencies to drive incremental growth and profitability. Marginal pricing increases are welcomed, but tangible stages/day improvements are much more powerful in improving cash flow generation on a per frac spread, per wireline truck, or per pump-down crew basis (really any product/service that is priced per-stage). However, given the confluence of operational factors at play during an unconventional completion operation, the efficiency equation remains an extremely complex and multivariate exercise in optimizing both supply chain logistics and field-level (per stage) execution. We enumerate just a few of the key operational inputs below:

- Per-stage services (frac, wireline, pump-down) – In a typical single-well plug-and-perf completion, stages are completed from the toe (furthest target zone at the end of the lateral) to the top-most zone, near the kick-off point from vertical section to horizontal (a diverter compound can be pumped to stimulate stages out-of-order, but in general the completion progresses uphole). To set up for pressure pumping stimulation, a wireline plug and perforation gun are pumped-down into the lateral using auxiliary pumping units (at low flow rate and pressure). The plug is set, the perforation gun is fired through the steel casing into the target reservoir, and the wireline is then pulled out-of-hole. The WL pressure control equipment is removed from the wellhead, the frac iron is subsequently rigged up onto the well, and stimulation can begin. A typical stage takes at total of 4-6hrs, 1-2hrs for the WL run, and 3-4hrs for the frac stimulation.

- Rental products/services (wellsite proppant/fluid management, crane, pressure control, frac tanks, generators/lighting/) – Third party rental equipment and services that are not billed on a per-stage basis are also important efficiency inputs. For these inputs, E&P customers need to weigh the day-cost vs. service quality tradeoff. In some instances, E&Ps outsource the sub-contracting of these services to the pressure pumping provider to optimize field efficiency.

- Consumables/supply-chain (proppant, chemicals, water, rail, transload, LML trucking) – As has been well-documented over the past several quarters, no completion operation can progress without ample supply of pressure pumping consumables. The consumable supply chain and, particular, rail/last-mile-logistics (LML) systems are crucially important in keeping operations running at the wellsite.

- HSE, data interpretation, cross-functional decision-making – Beyond the operational experts representing the various service providers on location, the E&P customer also has personnel both at the wellsite and in-town monitoring progress in real time. Given the multitude of E&P workflows engaged at any particular time during the completion, operations can be both bolstered and hindered by the decision-making process. Logistically, Health, Safety & Environment (HSE) managers are critical in shift-changes, daily company/state reporting, and handling related emergencies. Meanwhile, completion engineers, geologists/geophysicists, and production engineering teams are all simultaneously engaged in monitoring, interpreting, and reacting to real-time data feedback. For larger completion projects with prominent E&Ps and bigger service providers, bottlenecks are often the people involved in the decision-making process, rather than equipment, consumables, and field personnel charged with executing the operation.

The importance of an extra stage per day. While we have limited information regarding stage pricing and input costs, recent conversations with our pressure pumping coverage universe have elucidated just how important incremental throughput gains are versus incremental pricing gains (in terms of maximizing EBITDA generation). We conjecture that reasonable Permian pricing/operational assumptions include $50-$55k/stage (sand/LML sourcing-dependent) at ~25% gross margin and roughly 4-6 stages/day (completion design-dependent). Moreover, the majority of our coverage currently supports ~$750k in SG&A per spread per quarter. With these round number assumptions in mind, it is not unreasonable to assume that given a consistent 25 working days per month, efficient pressure pumpers can achieve ~$16-20 million in annualized EBITDA/spread. In the sensitivity analysis below, we take a simplistic approach to flat days/month (devoid of seasonal/holiday impacts), flat gross margin, and flat G&A per spread to determine the annualized EBITDA impact of both increases in stage pricing and increases in stages/day. *Our findings indicate that in the current (estimated) stage pricing regime, an incremental stage/day outweighs a $5k/stage pricing increase until throughput reaches a whopping 9 stages/day clip*. We would also speculate that such efficiency gains are also rewarded with higher pricing and better backlog visibility, as the E&P also benefits from a quicker-than-expected operation through smaller-than-expected day-rental costs.

Figure 2. The Power Of The Extra Stage (Ann. EBITDA/spread sensitivity at 25% gross, 25 days/m, $750k G&A/m per spread)

Annualized EBITDA/spread	Throughput (stage/day)								Pricing Impact
Pricing ($k/stage)	3	4	5	6	7	8	9	10	
$40	$9.0	$12.0	$15.0	$18.0	$21.0	$24.0	$27.0	$30.0	
$45	$10.1	$13.5	$16.9	$20.2	$23.6	$27.0	$30.4	$33.7	**13%**
$50	$11.2	$15.0	$18.7	$22.5	$26.2	$30.0	$33.7	$37.5	**11%**
$55	$12.4	$16.5	$20.6	$24.7	$28.9	$33.0	$37.1	$41.2	**10%**
$60	$13.5	$18.0	$22.5	$27.0	$31.5	$36.0	$40.5	$45.0	**9%**
$65	$14.6	$19.5	$24.4	$29.2	$34.1	$39.0	$43.9	$48.7	**8%**
$70	$15.7	$21.0	$26.2	$31.5	$36.7	$42.0	$47.2	$52.5	**8%**
$75	$16.9	$22.5	$28.1	$33.7	$39.4	$45.0	$50.6	$56.2	**7%**
Throughput Impact		**33%**	**25%**	**20%**	**17%**	**14%**	**13%**	**11%**	

Source: Company data, Evercore ISI Research

RigLock – Another Efficiency Driver Gaining Steam In U.S. Shale

'Not so new' technologies slowly making an impact in the laggard Permian. For investors who are well-versed in the basin-level nuances of the pressure pumping market, a major source of pushback is that Permian growth should be punished due to the efficiency degradation observed in newer West Texas crews relative to more experienced crews in basins such as the Rockies and Northeast. Although unfair in other product/service lines, one can perhaps characterize the Permian frac market, specifically, as one that has lagged in terms of technological and technique adoption. An example of this is the fact that much of the drilling activity in the legacy Midland basin, by virtue of its stacked reservoir stratigraphy (and perhaps lack of E&P consolidation), continues to be by vertical/short horizontal design. Similarly, newer completion techniques/hardware (namely sliding sleeves, diverter technology, pinpoint frac design) seem to be having trouble penetrating an archetypal plug-and-perf Permian unconventional market. These are among the many factors that contribute to the Permian being a "less efficient" completion market in terms of stage/day throughput, and while robust demand more than compensates service providers on the stage pricing front, it is clear that the next leg up for pressure pumping growth is rooted in continued efficiency gains. To this end, 'not so new' completion technologies continue to be introduced (either by service providers from learnings in another basin or by forward-thinking E&Ps with the scale to prove-out a new completion concept). *One well-documented example of this completion innovation is the zipper frac – which has unlocked myriad operational/geological efficiency gains in the Era of Mega-Completions*. Pad manufacturing/'cube development' are other aliases by which this broader well/stage down-spacing are known, and it is one of the major drivers behind the bifurcation of NAM shale service market (as the associated service intensity/complexity has created both actual barrier-to-entry and also the opportunity for service providers to demonstrate meaningful efficiency-savings through execution excellence and/or unique technology).

Zipper fracs possess their own bottlenecks. While nowhere near a new technique, having been developed and honed over ~a decade after being first introduced in the Barnett (the 'Petri-Dish of shale), the zipper frac is revolutionary from an efficiency standpoint because it allows for the simultaneous stimulation of a frac stage on one well and the perforation of the next frac stage on an adjacent well. Recall, that in a single-well plug-and-perf configuration, the frac crew and WL/pump-down/crane crews alternate between stimulation (pumping) and perforation; the time associated with switching from WL to frac is costly given both the steep rental costs of auxiliary equipment/personnel and also the time lost before putting the particular well on production (POP). Due to the intense pressures at which the majority of unconventional wells are drilled, and due to the intense flow rates at which treatments are pumped into the formation, extra time needs to be taken to ensure safety on surface – this involves having to 'pressure test' the wellhead pressure control equipment before executing the next stage perforation/stimulation. Together with the physical toggling of heavy iron/flow equipment/PCE between frac and WL operations, the pressure test is time consuming, and lost minutes add up over the many stages per well and many wells per pad. Often during zipper operations, the frac crew will have to wait for the WL crew to rig up on the lead well, pressure test, and deploy the perforation explosives into the well (as pumping cannot begin while armed explosives are on surface, as per even the most relaxed HSE standards). As such, zippers are bottlenecked when the frac crew "runs into" the leading WL/pump down operation, yielding excess lost time that isn't necessarily characterized as NPT (as no failure has occurred) but the time is lost nonetheless.

RigLock seems to be the 'next best widget' of 2018 as adoption picks up speed across key hotbed basins. RigLock is another 'not so new' technology that appears to have made landfall in the Permian (and other key basins) in early 2018, and is quickly gaining adoption among the premier pressure pumping contingency. Simply put, RigLock is a remote-operated wellhead add-on that allows for the quick connect/disconnect of crucial pressure control equipment during perforation and stimulation operations. The one-size-fits-all principally allows both WL and pressure pumping to quickly rig up, pressure test, and begin operations through PCE that would otherwise need to be installed manually by personnel suspended at-height. The technology was pioneered by Shell and Renegade Wireline in Appalachia, and has since been manufacturing by FHE . Below are the key advantages of RigLock and analogous technologies currently offered by just a handful of equipment providers:

- **Quick connect/disconnect of WL/frac PCE** – In traditional operations, personnel working in a man-basket at height are charged with unscrewing the wellhead "night cap" and then aligning, signaling to the crane, and guiding the PCE onto the wellhead and securing threads with heavy hand tools. The RigLock allows the crane

operator to guide PCE into the RigLock device without personnel at the wellhead, and a remote switch locks and seals the gear in place (at which point pressure testing can begin).

- **Reduces personnel exposure at the wellhead** – The area immediately around the wellhead is known as the "red zone" due to its proximity to potentially dangerous pressures and fluids. RigLock minimizes personnel HSE exposure during well swaps with the remote actuation of the piston locks.
- **Streamlines pressure testing/ensures consistent seal upon installation** – Pressure testing is often the most time-consuming part of the well swap, and variants of the RigLock technology streamline this process by 1) including a specially-designed control module/pressure testing hookups to make testing more efficient, and 2) ensuring a consistent, quality connection that is less prone to pressure test failures (helping avoid lengthy bleed-off, re-installation, and re-testing.

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Figure 3. Traditional PCE Installation Involves Personnel Working At-Height With Heavy Hand Tools

Source: Renegade Wireline youtube: https://www.youtube.com/watch?v=VIO_yiDT1sk

Figure 4. RigLock Allows PCE To Be Detached/Stabbed & Locked Quickly By Crane/Remote Switch

Source: FHE RigLock https://www.youtube.com/watch?v=uJqoaVfO1YQ

Quantifying the efficiency gains – what pressure pumpers are saying about the RigLock. Admittedly, we were initially alerted of the substantial efficiency benefits of the RigLock by our E&P counterparts, but upon further engagement with the vast majority of pressure pumpers within our coverage, we quickly learned that RigLock is gaining appreciable adoption momentum in the Permian (and excitement is palpable regarding the potential efficiency gains). *We want to be clear – due to the multivariate nature (and sheer variability) of completion designs in different wells/pads/fields/basins, the RigLock is not the "Silver Bullet" of efficiency technologies, and the associated benefits of RigLock are moot without the many moving operational/logistical parts keeping pace with the incremental efficiencies of the technology.* We also note that we are relatively early In the adoptlon process, so clear efficiency benefits are not yet readily quantifiable. Furthermore, it is our opinion that RigLock gains are very much a function of how efficient the particular E&P/service provider was *before* during well swap operations. It is a culmination of these key factors that lead to a modest discrepancy in the management feedback below:

- **SLB – SLB rolled out RigLock across a number of crews several months ago and adoption has been rapid (compelling the company to potentially look into its own competitive product).**
- **CJ** – The company has been signaling its purchase and adoption of a RigLock-type technology in recent investor presentations (Capex slide – efficient completion/PCE equipment). Furthermore, the company continues to develop proprietary iterations of the technology in-house at its R&T center to accommodate non-plug-and-perf completion techniques (i.e. a RigLock port for remote ball-drop during sleeve operations). The company estimates that roughly 25-33% of its wireline crews will utilize a variant of the technology (~50% of plug-and-perf WL crews). Anecdotally, the company noted the high cost of the system and the low-hanging opportunity in the Rockies basins (where smaller/quicker stages yield more frequent frac/WL bottlenecks). *We note that CJ's frac fleet profitability is among the larger positive inflections observed in recent quarters, which beyond a broader pricing push could be characteristic of the company's leading edge adoption/R&D push with RigLock.* **Anecdotally, time savings of 20-30 min/well swap have the potential to yield an additional 1-2 stages/day depending on completion design and extenuating factors.**
- **LBRT** – The company has purchased two systems (enough hardware to outfit an entire pressure pumping spread, multiple well heads, for an estimated total of $500k). The first system was deployed with a customer in Texas and the second will be deployed in the DJ with one of the company's most efficient crews/customers. This second installation will be very telling of the efficiency opportunity given that the crew is already achieving leading-edge throughput. *As we postulated earlier in the note, one incremental stage/day equates to an incremental ~$3-4 million in annualized EBITDA/spread, and with minimal incremental capex implies plenty of return on the initial $500k investment.* **Too early to quantify time savings, but HSE exposure benefits more than justify at least trialing in key basins.**
- **PUMP** – In the eyes of the investment community, efficiency upside is perhaps the most needle-moving for a Permian pure play that has largely been a non-participant in the throughput superiority of a lumpier, weather-driven Rockies region. PUMP rolled out RigLock in late '17/early '18 and the five (out of nineteen) crews running it "love it" for the ease-of-use benefits. Part of the adoption is customer-driven, while PUMP has turned several other E&Ps onto the system. **PUMP reiterates the 20-30 minute/swap savings and more consistent pressure tests as the basis for the incremental 'stage or two' per day.**
- **BAS** – Several of BAS' customers use RigLock, but the high cost is not justified in all completion configurations, and adoption remains relatively muted in the Permian, specifically. BAS does not appear to be actively trying to convert its customers to the technology. **The company called out the HSE benefits and modest time savings per swap consistent with discrete guidance given by SMID cap peers.**
- **FRAC** – The company is familiar with and using the technology, which makes sense to us given that it originated in Appalachia (where FRAC has a strong presence). **The company is seeing efficiency gains on the order of 20-30 minutes per swap.**
- **RES** – The company's operational management called out seeing RigLock technology deployed on a handful of occasions, but does not appear to be engaged in the adoption beyond E&P customers requesting it with wireline. **We note that RigLock, if not purchased directly by the frac provider, seems to be a PCE rental charge-back that is most likely lumped in with the WL field ticket (not part of the frac bill).**

Conclusion – too early to tell, but 20-30 minutes/swap could unlock an incremental stage/day and upwards of ~5.0 million in annualized EBTIDA/spread. All else equal, and assuming no additional bottlenecks appear with widespread adoption of RigLock, we believe the incremental 20-30 minutes between well swaps could, over the course of a day, yield an incremental 1-2 stages/day (in reality, the improved throughput places more strain on other parts of the completion value chain, so likely a naïve assumption to draw). **On an annualized EBITDA basis, the RigLock efficiency gain is dependent on stage pricing, but we see a path toward upwards of $4-$5 million in EBITDA/year per spread.**