How to Solve Your Long Lateral Problems

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Executive Summary

Longer laterals impose challenges with current completion methods. The low-price environment in the oil and gas field forces operators to focus on cost-saving methods anywhere practical. Wells with longer laterals have become more prominent in the industry due to their additional contact with the formation, increased productivity and the ability to save money. However, conventional completion methods are a limiting factor due to their decreasing efficiencies with respect to lateral length and problems that thereby occur. These wells push methods, like coil tubing, to their mechanical limits. As lateral lengths increase, conventional methods become obsolete as new technologies come to fruition.

Challenges with Longer Laterals

The cyclical nature of the oil and gas industry and most recent downturn presented companies with a challenge; increase efficiencies at the wellhead, or risk losing their competitive edge. Increased productivity in multi-well pads, improved drilling rates, proppant use, and longer laterals have all been implemented to reduce the costs in drilling and completions. Advanced bottom hole assemblies and directional drilling have allowed for longer laterals; however, problems still remain using conventional completion methods. Operators are losing time and production through irretrievable frac plugs in the toes of long lateral wells. The inability to drill out plugs at the toe presents one major question for operators – is the additional production and cost savings worth the risk and uncertainty of drilling an extended lateral well?
Existing Solutions

Coil Tubing

Coil tubing (CT) is a completions solution that works against the pressure of the well, using a continuous length of tubing for efficient well intervention operations. Traditionally, CT is an effective option for completing wells, but it becomes less efficient as the lateral length increases. When the coil tubing reaches approximately 6,000 feet in the lateral, its efficiencies decrease and complications begin to arise.

One type of complication is helical buckling, a form of buckling that occurs when the compressive forces cause the tubing to wrap around the inner diameter of the casing. This decreases the weight on bit (WOB) and rate of penetration (ROP), resulting in longer drill times and increased coil fatigue. Another type of CT complication occurs when the coil becomes fatigued at the gooseneck from extended time in one area due to reduced ROPs. The coil must be tripped out of the hole and cut in order to have a new area on gooseneck upon the return to depth.

Hole cleaning is another issue for CT and is from the lack of rotation and reduced annular velocity while milling or running in hole. Without rotation, getting debris to the surface becomes very difficult. This requires frequent short trips back to the kick-off point every 5 – 10 plugs or less as coil progresses deeper in the lateral. Coil tubing’s mechanical limitations are becoming ever more apparent as the industry continues to push for longer laterals.
Rig-Assist Snubbing Units

A rig-assist unit is a combination of a workover service rig and snubbing unit that provides the necessary rotation and durability to reach plugs in the toe of long laterals. Rig-assist, similar to coil tubing, operates on live wells but uses jointed stick pipe. The jointed stick pipe conveys the full torque of the swivel, thus eliminating the complications seen in the unstable coiled tubing. The advantage of a rig-assist package is its utilization of two unit in one. It is able to trip pipe using the snubbing unit during pipe light and the transition period, and quicken its trip time using the workover rig and its blocks during the pipe heavy period. The disadvantage of this package is that it requires two services to perform one operation in the well. It is vital that both services have exceptional communication for smooth operations. Other disadvantages are its power swivel limitations and the larger footprint required by the service rig. The rig-assist unit cannot handle the high torque requirement associated with extended laterals, for the high torque reduces the power swivel’s rpm and allowable circulating pressures. Additionally, the power swivel can take an excess of an hour to rig up and out. The package’s footprint is greater than 100’ in length and has a base beam that is 5’ x 40’, which creates difficulties in rigging up/down on pads with tight well spacing and infrastructure. This congestion on site introduces additional hazards and risks that must be mitigated.
Hydraulic Completion Units

A Deep Well Services hydraulic completion unit (HCU) is optimal for completing long laterals. It has successfully reached total depth (TD) on the top five longest drilled land completions in North America. HCUs’ sensitive jack enables precise WOB to prolong the bit’s life and increase efficiencies in milling. In nearly every drill out, HCU’s technology maintained efficiencies at TD and used only one bit. In case studies, these units drill out and circulate solids and sand debris in fewer hours than the number of plugs and have proven to rotate 50+ rpm in 20,000’ laterals. These two functions alone eliminate the debris and ROP issues seen in coil tubing. HCUs are similar to rig-assist units and use the same hydraulic system; however, they perform more safely and efficiently. HCUs’ overall footprint is 50% smaller than the rig-assist package and can be used on any size pad with a variety of different layouts. The HCU sits directly on top of the wellhead and needs limited space for the additional support equipment, giving customers options to re-enter and drill more wells on pads with existing wells and infrastructure.

Although it takes time to make and break the connections of jointed pipe, HCUs have proven to be far more efficient than coil tubing after 6,000’ of lateral length is reached, averaging between 50 - 60 joints per hour regardless of well conditions. These units are able to reach the toe in 20,000’+ laterals with consistent drill times from the first isolation plug to plug back total depth (PBTD).
Another significant advantage of the HCU is the single pick well to well rig over. The compact design enables a one connection rig over (including primary BOPs), greatly increasing efficiency and reducing exposure time to personnel. On average, a rig over with an HCU saves six hours or more compared to a workover rig and rig-assist snubbing unit. HCU's have ratings of pressure from 5,000 to 15,000 psi and hook loads from 142,000 to 300,000 lbs. The multifaceted units also perform fishing jobs, toe preparations with a TCP run, tubing installs, cleanouts, cementing, and other remedial work. The HCU has successfully eliminated the major issues and inefficiencies seen with conventional methods.
Cost Comparison

One concern with an HCU is the price comparison with other methods. The day rate of a CTU package and HCU package are nearly equivalent, around $45k and $55k respectfully. The HCU can reduce the costs associated with a chemical program up to 50% with its rotation capabilities and higher annular velocity. Unlike coil tubing, HCUs require a crane operator only during rig up, rig down, and rig over. While equivalent in cost, coil tubing still requires a workover unit to install production tubing post-drill out and creates additional planning of a second operation. Utilizing an HCU to drill out plugs and install production tubing saves time and money. Case studies have shown HCUs provide upwards of a 60% time reduction per pad and save substantial costs in mobilization when compared to coil tubing.

<table>
<thead>
<tr>
<th>CTU Package</th>
<th>HCU Package</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coil Tubing Unit</td>
<td>285K/300K HCU</td>
</tr>
<tr>
<td>*includes pumps, BOPs, and</td>
<td>*includes pumps, BOPs, and</td>
</tr>
<tr>
<td>coil*</td>
<td>work string*</td>
</tr>
<tr>
<td>$30,000</td>
<td>$37,700</td>
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<td>$5,000</td>
<td>$2,500</td>
</tr>
<tr>
<td>$7,000</td>
<td>$3,000</td>
</tr>
<tr>
<td>Chemicals</td>
<td>Chemicals</td>
</tr>
<tr>
<td>$10,000</td>
<td>$3,500</td>
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<tr>
<td>$15,000</td>
<td>$7,500</td>
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<tr>
<td><strong>Total</strong> $45,000</td>
<td><strong>Total</strong> $43,700</td>
</tr>
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</table>

Source: Several Appalachian E&P Companies
HCU Technology

Although snubbing is known for being a higher risk operation, hazards seen in the past have been mitigated with HCU technology. This technology was implemented to create fail safes and efficiency improvements that correct problems and concerns seen with snubbing operations.

Interlock System

In the past, human error was the cause of dropped and launched pipe incidents. The HCU’s slip interlock system solves this by removing the human error factor, preventing the operator from opening both sets of corresponding slips at once. The system will not allow the current slip to open without the other having a true bite. With the use of this technology, the potential for dropped or launched pipe is eliminated. The interlock system not only prevents launches and drops, it also notifies the operator if there is a sheared slip with proximity sensors. These sensors detect any fault in the slips and ensure safe working conditions.

Ram Indicators

When the wellhead surface pressure is above approximately 3,000 psi the operator will snub ram to ram. Stripping rams are fit to the OD of the pipe and are required to be opened when a collar passes through. Previously, operators had to make the dangerous assumption that a ram was truly closed and sealed around the pipe. With ram indicators, this is no longer an issue. The technology notifies the operator whether or not a ram is completely sealed. This prevents gas leaks and damage to the rams from collars tagging them.
Internal Buckling Guides/Telescopic Stroke Guides

Buckling pipe is another concern with snubbing. HCU's avert this situation with internal buckling guides and telescopic stroke guides that brace unsupported lengths of pipe and prevent buckling.

Internal buckling guides are located between both stripping rams and the telescopic stroke guides are situated between the traveling and stationary slips. Slip guides are also utilized throughout the unit to support the pipe above each slip bowl. These guides support the pipe when it is run during the hole in high-pressure operations.

Other Technologies

Other technologies incorporated into the HCU are the auto driller, rpm control, rotary guard, slip gallery, expansion spool, three-winch payout mode system, mousehole slip, and integrated equalize loop. These advancements give operations a perfect balance between safety and efficiency. A few of these features are explained below.
The slip gallery allows the operator to switch between rotary and trip modes without disconnecting the hydraulic hoses. It also handles the high torque requirements associated in long laterals, unlike rig-assist units, which allows for a more safe and efficient drill out operation.

The three-winch payout mode system enables operators to run either direct or counterbalance modes. While the direct mode is used to tripping pipe, the counterbalance has the ability to stay in tension mode without manipulation during drilling or rotating situations, avoiding the potential for miscommunication.

The expansion spool provides simulated string weight up to 60,000 lbs. for pipe light or low string weight scenarios. The traveling and snubbing slips are engaged while rotating during these times. It is commonly used to mill hydrates and released frac plugs near the surface.

The mousehole with incorporated slips allows for a single joint to be installed in the work baskets enabling the crew to make quick connections, averaging 60 seconds per joint, and limits the noncirculating time. This technology provides the operators the most advanced equipment to safely and efficiently perform well intervention operations.
Case Studies

Two large global operators with divisions in the Northeast wanted to reduce the cost and time associated with plug mill out and tubing installation. Both companies were originally using coil tubing units for mill out operations and a workover rig to run tubing. The companies conducted separate studies to determine if HCU could provide a better service.

The HCU was determined to be more successful than coil tubing. The two companies found that they were able to see better key performance indicator results by utilizing HCU in the longer lateral wells.

Company 1

Past Method: (Three service operations)

• Coil Tubing for mill out operations and packer installation
• Run tubing with a workover rig
• Set tubing hanger with lockdown pin
• Install production tree

New Method: (One service operation)

• Utilize HCU for mill out operations and tubing installation (no packer)
• Set tubing hanger with latch retention system
• Install production tree

The Case for Change: The company did not believe that coil tubing could make it to TD as lateral lengths increased. They were also able to eliminate the packers because of the HCU’s ability to run in live wells, giving them confidence that the new method was able to decrease cycle time and operating cost.
Results:

- Mill time per plug was improved by almost 40%. The HCU averaged 0.35 hours per plug and the CTU averaged 0.58 hours per plug. (Figure 1)
- It was determined that at 6,000 feet HCU had a quicker drill out time than coil tubing. (Figure 2)
- The HCU had a consistent run in hole time even as the lateral reaches 8,000 feet. (Figure 3)
- The HCU topped the leaderboards for cost per lateral, hours per 1000 lateral feet, plugs drilled in 24 hours, and others. (Figure 4)
- The HCU saved Company 1 $76,440 per well. This figure did not account for the turn in line (TIL) cycle time. (Figure 5)
Figure 2: Drill out time comparison between Coil Tubing Units and Hydraulic Completion Units

Drill out time CTU vs HCU

Source: Completions Superintendent and Engineers, Global E&P Major

Figure 3: Hours per 1000 feet comparison

Hrs/1000’ comparison

Source: Completions Superintendent and Engineers, Global E&P Major
Figure 4: Snubbing unit metrics by job

<table>
<thead>
<tr>
<th>Date</th>
<th>Source</th>
<th>Value</th>
<th>Unit</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>11/22/2016</td>
<td>Deepwell</td>
<td>1.5 hours</td>
<td>Skid Time</td>
<td>Time from start of NO BOP activity code on previous well to start of NO BOP activity code on current well</td>
</tr>
<tr>
<td>12/6/2016</td>
<td>Deepwell</td>
<td>12 hours</td>
<td>Full BOP Test Time</td>
<td>Time from start of BOP test to RI BHA</td>
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<td>11/22/2016</td>
<td>Deepwell</td>
<td>3.75 hours</td>
<td>Shell BOP Test Time</td>
<td>Most plugs drilled in any 24 hr period</td>
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<tr>
<td>11/24/2016</td>
<td>Deepwell</td>
<td>26 plugs</td>
<td>Plugs Drilled in 24 hrs</td>
<td>Definition: From the end of BOP pressure test to the end ID drilling BHA phase</td>
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<td>Deepwell</td>
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<td>11/25/2016</td>
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<td>12/8/2016</td>
<td>Deepwell</td>
<td>8</td>
<td>Hours / 1000' lateral feet (Pad)</td>
<td>Definition: From the end of BOP pressure test to the end ID drilling BHA phase</td>
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<td>12/14/2016</td>
<td>Deepwell</td>
<td>$42.55/ft.</td>
<td>Cost / lateral feet (Pad)</td>
<td>Definition: Total cost from start of RI on first well to RI on final well / total lateral footage on pad</td>
</tr>
</tbody>
</table>

Source: Completions Superintendent and Engineers, Global E&P Major

Figure 5: Company 1 scenario assumptions and savings calculations

Assumptions & savings calculation

Current Baseline Costs:
CTU + Tubing installation - tangibles (trees, tubing, packers) = Total costs for comparison
$2,729,808 + 1,022,963 - 120,000 = $3,214,621 for 10 wells

Improved Case Costs:
Snubbing costs (plug mill out, tubing installation, and tangibles) = Total costs for comparison

7 Well Average on 10 Wells = $245,022
$321,462 - $245,022 = $76,440/well Savings

Source: Completions Superintendent and Engineers, Global E&P Major
Company 2

**Past Method:** (Three service operations)
- Coil tubing to drill out
- Wireline to set packers
- Workover rig to install tubing into the packer

**New Method:** (One service operation)
- HCU to drill out
- HCU to set packer and install tubing in one run

**Issues:** As the lateral lengths surpassed 6,000’ coil tubing could no longer reach the toe to drill out composite frac plugs. The coil often got stuck and required a variety of different options to break free. It also made frequent short trips to the kickoff point, fatigued the coil, and had lower ROP, creating poor hole cleaning conditions.

**Solution:**

The company decided to implement HCUs because it was “designed for their needs.”

- Ability to rotate resulted in much better hole cleaning conditions
- High hook load, high annular velocity, and consistent rotation greatly reduced the likelihood of becoming stuck
- Sets packer and installs tubing in one run
- Drills out, runs tubing, and sets packer all in one rig up
Results:

The HCU reduced cycle time by 60% and saved on average $600,000 per pad. (Figures 6 - 7)

Figure 6: Coil Tubing versus Snubbing Days

Source: Completions Superintendent and Engineers, Global E&P Major

Figure 7: Coil Tubing versus Snubbing Days (normalized by lateral length)

Source: Completions Superintendent and Engineers, Global E&P Major
What to Look for in a Solution

It is important to choose the correct company with similar values. In the oilfield, safety is number one and efficiency is number two. Below are some key points to look for in choosing a hydraulic completion company partner.

- Low Total Recordable Incident Rate
- Highly maintained equipment
- Thorough Standard Operating Procedure
- Stop Work Authority
- Competency training
- Torque and Drag Modeling
- Accredited certification
- Quality Management System
- Behavioral Based Safety
- Hazard ID and Trending Cards

Conclusion

Hydraulic Completion Units have changed the unconventional shale play. Today, more and more companies are utilizing HCUs for their high-pressure, long lateral completion programs. The technology has proven to provide the safest and most efficient completions for these types of wells. With longer laterals becoming more prominent and the industry’s demand for safer, more efficient, environmentally conscious operations, the HCU is leading the way.
Deep Well Services

Established in 2008, Deep Well Services (DWS) is an oilfield services company specializing in completion, workover, and well servicing operations in Pennsylvania, Ohio, New York, West Virginia, and Texas. The company leads the industry in long lateral (10,000'+) completion drill outs with the top five longest laterals in North America. In 2017, DWS completed the two longest laterals in US onshore history, the Mercury B5H 20,800’ lateral and the Outlaw B5H 20,400’ lateral. DWS earned this achievement through its core values and “Great 8” culture.

The safety, maintenance, state of the art equipment, and most importantly their people have brought DWS to the top. Safety first is not only a core value of the company, it’s a lifestyle for the team. It’s expressed every day that hazard ID and trending (HIT) cards and stop work authority are to be used for any concerns. The thorough SOPs and torque and drag modeling have also contributed to their success. They joined an elite group of service companies that achieved the API Q2 certification making them the only snubbing organization to earn the world’s most advanced industry standard. DWS’s designation as API Q2/ISO9001 certified exemplifies their commitment to continuous improvement while mitigating risk and increasing efficiency. DWS hydraulic completion units are creating opportunities for long lateral, high-pressure wells; however, the people are the backbone that drives these units to their full potential. The employees are the best in the industry. Everyone at DWS is entered into the “DWS Competency Program” which evaluates not only training requirements, but job skill and proficiency. DWS has utilized cutting-edge technology and top-tier talent to build and maintain its position as a leader in the industry. At Deep Well Services, people, safety, and quality are more than a priority; they are a value.

For more information, please contact Matt Tourigny, V.P. of Marketing