Nine

CASE STUDY

COILED TUBING SOLUTIONS

Haynesville Operator Saves More than 55 Days and USD 4 Million with Unique High-Pressure CT Fishing Technique

LESSONS LEARNED RESULT IN A 75% REDUCTION IN AVERAGE DRILLOUT COST PER FRAC PLUG

Challenge: Cost-effectively fish 4,528 ft of stuck coiled tubing (CT) without formation damage and optimize frac plug drillout in future wells in the Haynesville Shale.

Solution: Devise an innovative fishing technique to expedite recovery and conduct a detailed study with recommendations for subsequent wells.

Results:

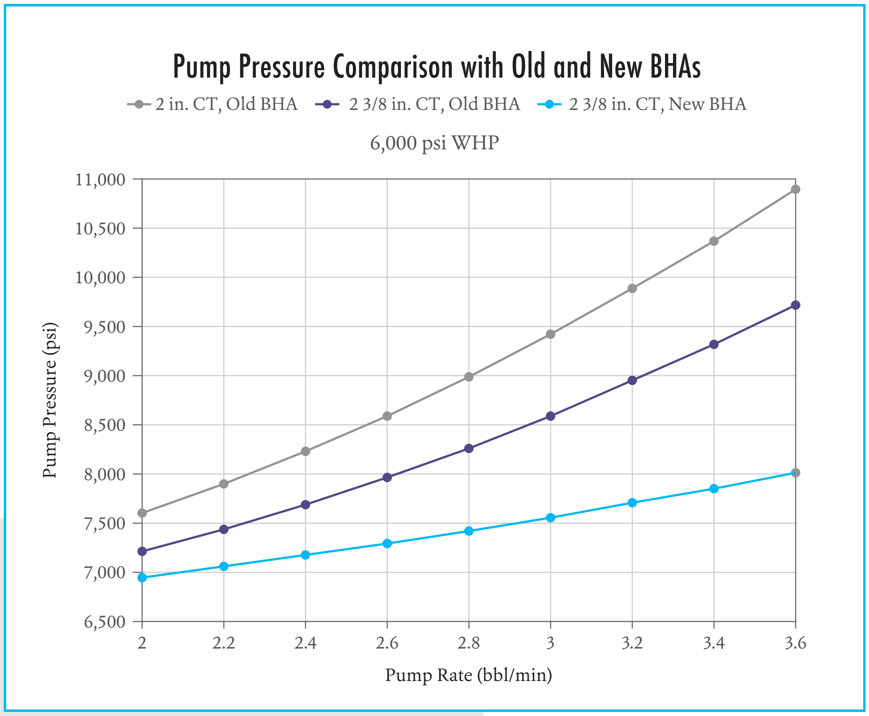
- Recovered the fish while saving the operator more than 55 days and USD 4 million.
- Lowered average drillout cost per plug to one-fourth across 14 wells.

CHALLENGING WELL CONDITIONS HINDER FRAC PLUG DRILLOUTS

Multistage hydraulic fracturing using plug and perf is the dominant completion method in the Haynesville Shale, the third largest shale play in the US. A Haynesville Operator used the technique to stimulate a well from 13,000 to 17,580 ft measured depth. Subsequently, 2 in. CT was deployed to drill out the composite frac plugs.

In this overpressured, high-rate gas formation, high reservoir pressure gradients limit CT circulation rates due to surface pump limitations. A balanced to slightly overbalanced well condition is maintained during frac plug drillout to prevent gas from entering the wellbore and increasing wellhead pressure. Such an event would further diminish circulating rates and increase the potential for stuck pipe. High-viscosity gel sweeps along with high concentrations of friction reducer was used during the drillout in an attempt to aid in solids removal. Additional high-viscosity gel sweeps of steadily increasing volume were pumped at frequent intervals. The result was a fluid system saturated in polymer, with increased viscosity and decreased friction reduction ability.

In addition, bottomhole temperatures approach 350°F, reducing the effectiveness of downhole chemicals and limiting the working life of the bottomhole assembly (BHA), including the positive displacement motor (PDM). The first 25 plugs were milled at an average rate of 18 min/plug, but on reaching the 26th plug at 16,528 ft the motor locked in a stalled condition, resulting in loss of circulation and a stuck CT string. After numerous unsuccessful attempts to free the CT, fishing was the only alternative.



Use of an optimized BHA and 2 3/8 in. CT achieves a given flow rate at a significantly lower pump pressure. (Adapted from Skufca and Stabler, 2018. Copyright 2018 Society of Petroleum Engineers, reproduced with permission.)

COST-EFFECTIVE RECOVERY OF STUCK CT REQUIRES NOVEL APPROACH

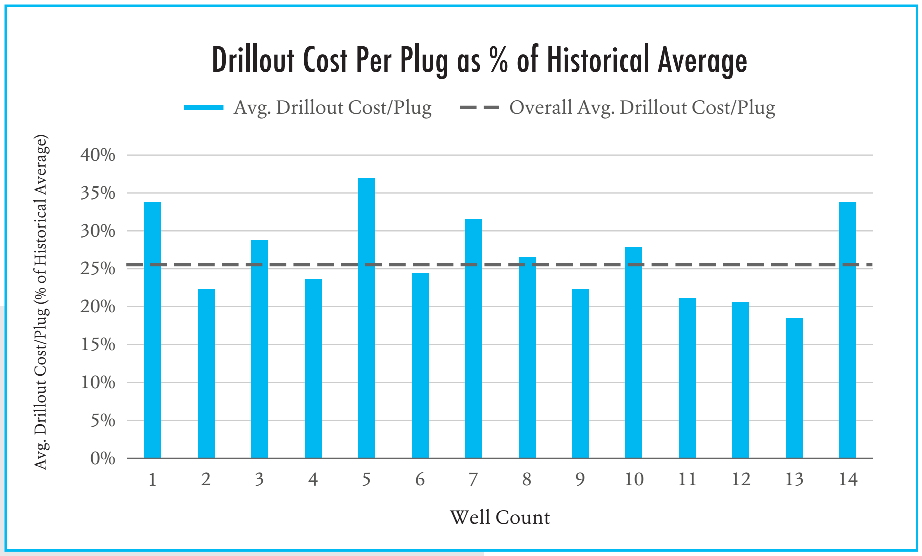
Pumping down a free-point indicator tool was impossible because the PDM was in the stalled position. The CT was therefore cut above the kickoff point and 12,000 ft were recovered, leaving 4,528 ft in the well. The top of the CT was left in the vertical section to facilitate latching onto the fish. With a shut-in wellhead pressure (WHP) of 6,000 psi, various alternatives for fishing the CT were considered.

- A workover rig would require pressure balancing the well with 17.5 lbm/gal mud or brine, risking formation damage or significantly escalating costs and HSE challenges.
- A snubbing unit would entail cutting the fish in 60 ft increments, requiring more than 75 trips and 75 days to recover 4,528 ft of tubing.
- Various fishing methods using CT had a low chance of success, were untried, or posed well control risks.

To reduce the job duration associated with a snubbing unit and the risks associated with CT, Nine Energy Service (formerly RedZone Coil Tubing) proposed a novel hybrid approach using both these systems in conjunction with a slickline unit. After a detailed planning exercise involving all parties, the recovery operation commenced.

The well was first loaded with $CaCl_2$ fluid to reduce the wellhead pressure to 3,800 psi for a greater margin of safety. A rig-assist snubbing unit then rigged up atop the CT BOPs. The snubbing unit ran a 2 7/8-in. workstring with fishing BHA to latch the 2 in. CT fish, pulling the fish into tension.

An initial wash run using 1¼ in. CT was made running through the 2 7/8-in. workstring and into the 2-in. CT string. Following the wash run, a pressure-actuated radial jet cutter was run until reaching friction lock-up depth of 14,925 ft, cutting the 2-in.CT string. The 1¼-in. string was pulled out and rigged down. A pump through plug was set inside of the 2 7/8 in. to facilitate pulling the workstring to surface. The snubbing unit retrieved the 2 in. CT fish, hanging it off in the CT BOPs at surface. Subsequently, slick line set two bridge plugs at the bottom of the CT fish providing wellbore isolation. Finally, a 2in. CT unit made the connection to the fish and spooled 3,000-ft-from the well without incident.



System optimization reduced the average drillout cost per frac plug by 75%. (Adapted from Skufca and Stabler, 2018. Copyright 2018 Society of Petroleum Engineers, reproduced with permission.)

OPERATOR REGAINS WELL IN 18 DAYS AND ACHIEVES 75% REDUCTION IN SUBSEQUENT DRILLOUT COSTS

The entire operation was completed in 18 days without any HSE incidents at a saving of approximately 60% compared with using a work over rig or a standalone snubbing unit. A second run to recover the remaining 1,528 ft of CT was considered but further production delays were unfeasible. More than half the wellbore was returned to production clear of any obstructed flow.

After a detailed job analysis, Nine Energy Service made several recommendations for future wells.

Increasing turbulence by increasing flow rate and decreasing viscosity significantly improves hole cleaning and reduces risks during CT drillouts. Increasing the flow rate was accomplished through CT selection, optimizing the BHA and monitoring fluids.

A custom designed 2 3/8 in. string with tapered wall thickness was selected for future work enabling an additional 15% increase in pump rate over the 2 in. CT.

The BHA was optimized to decrease the pressure drop through the tools by maximizing the inside diameter and eliminating unnecessary tools which lead to an additional 25% increase in flow rate. In addition to maximizing BHA ID and selecting a more efficient motor, a roller cone bit was recommended. It requires less torque—which equates to lower differential pressure across the motor—and generates smaller cuttings that are easily circulated out of the well. A flow-regulated diversion valve is preset with a fixed flow rate to the PDM, irrespective of the pressure through the PDM. As a result, the motor is never starved of fluid flow, while excess flow is diverted away from the motor, further reducing the pressure drop through the BHA. With the enhanced BHA and larger CT, a flow rate of 3 bbl/min, for example, can be achieved with nearly 2,000 psi lower pump pressure at the surface. An additional benefit is prolonging motor life by not over speeding at higher flowrates.

Finally, to increase well cleaning efficiency, a Reynold's number >20,000 is required. Use of a robust nonviscosifying friction reducing polymer, a program of regular viscosity control during the operation, the elimination of gel sweeps, the enhanced BHA, and the larger CT yield a Reynold's number greater than 36,000, effectively transporting debris out of the lateral. This reduces the need for wiper (short) trips , lowering the risk of sticking and the total time in the well. The cumulative effect of this optimization is a 75% drop in the average drillout cost per plug, as evidenced across 14 wells to date. Read SPE-189951 for details.