A Paradigm Shift in Drilling Frac Plugs in Extended Laterals - A Permian Basin Case History

SPE-201412-MS

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ABSTRACT

Wells in the Permian Basin continue to increase in technical complexity and lateral length, testing the limits of traditional completion practices in unconventional wells. Coiled tubing (CTU) has been the standard method for drilling out frac plugs in the basin but has mechanical limitations in extended-reach and high-pressure laterals. Due to the increasing well complexity, this major E&P operator begun using DWS Hydraulic Completion Units (HCU), to drill out frac plugs in the Permian Basin. The HCU system can provide a reliable and cost-effective means to cleanout laterals in the Permian while reducing mechanical risk. The purpose of the paper is to present case histories from a major leading E&P that illustrates the positive impacts of DWS HCUs on their field operations. This SPE-201412 paper will also detail the evolution of the HCU over time to its current state of the art stand-along rig less system.

CHALLENGE

As lateral lengths and down-hole uncertainty/complexity increased in the Permian, challenges began to arise while drilling out frac plugs with a CTU.

- A large increase in chemical usage, specifically pipe on pipe (POP) friction reducer.
- Cuttings bed forms appeared on the low side of the wellbore. This creates additional friction between the coiled tubing and casing which can lead to excessive pick up weights, decreased ability to reach plug back total depth (PBTD), and stuck pipe. Viscous sweeps are generally pumped after every plug and range in size from 5 to 10 barrels in an attempt to circulate as much plug debris and sand out of the well as possible. Although the sweeps are effective in cleaning debris from the wellbore, a cuttings/sand bed remains.
- Some fields may have depleted "pockets" due to past production in the area, which presents the potential for cross flows that can result in stuck pipe while drilling out frac plugs. These cross flows and the sticking issues associated with poor hole cleaning have resulted in multiple instances of stuck coiled tubing.

SOLUTION AND RESULTS

The major operator implemented a DWS HCU in March 2019 to drill out frac plugs in various fields of the Permian Basin in conjunction with CTUs. The following results are based on data from 2019 where ~50 wells were drilled out using the HCU and ~125 wells were drilled out with an average fleet of 2.5 CTUs.

- The added rotation aided in more efficient cuttings transport in the lateral which in turn resulted in a major reduction in chemical usage and cost.
- Use of POP friction reducer decreased significantly after the implementation of the HCU.
- The average volume of POP pumped by a CTU was 192 gallons per well while the HCU pumped 148 gallons per well on average.
- On roughly 15% of the wells drilled out with the HCU, less than 10 gallons were used.
- With the ability to rotate the pipe, plug debris and sand are not allowed to settle on the low side of the wellbore. This allowed more debris and sand to be transferred out of the wellbore which in turn reduced the frequency of viscous sweeps that are pumped.
- To test which sweep frequency would be required, sweeps were pumped at varying intervals and fluctuated between five to ten barrels in volume. Over time the torque began to increase with that schedule and required a surface to surface or bottoms up circulation before proceeding. Working through this trial and error method a standard sweep schedule consisting of a five barrel sweep every 2 plugs was developed. This has reduced the volume of Xanthan used during the drill out by an average of 69 gallons per well, as compared to coiled tubing.

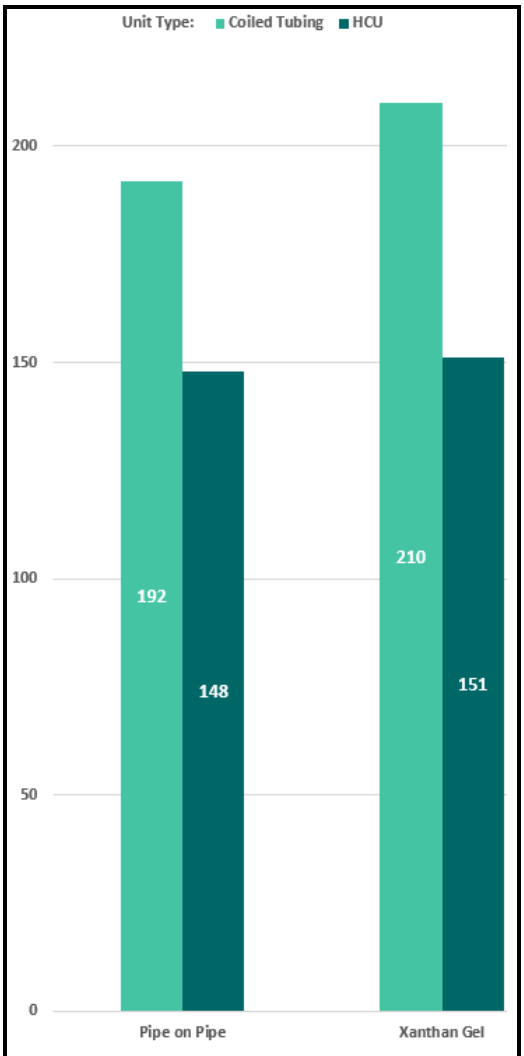

***Fig. 8** - Average volume of POP and Xanthan gel pumped per well for each unit type. This excludes friction reducer used to lower pump pressure.*

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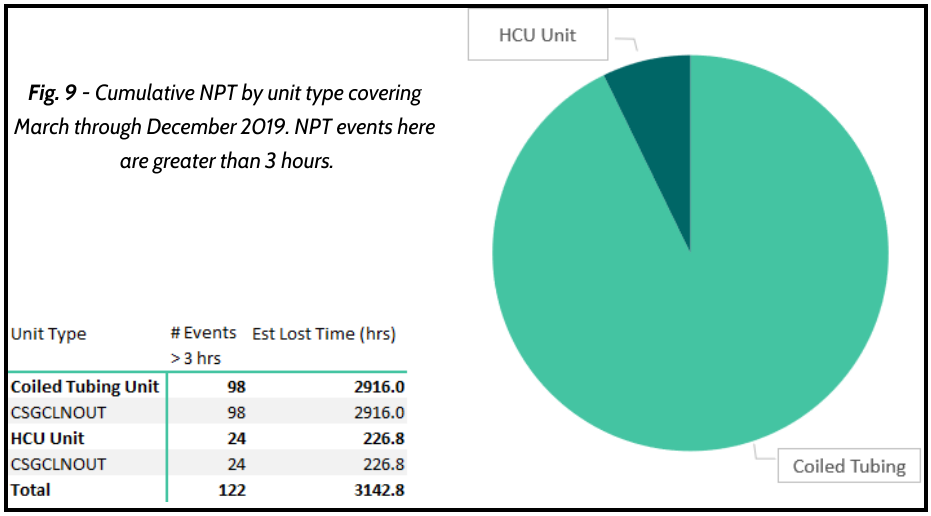

Fig. 9 - Cumulative NPT by unit type covering March through December 2019. NPT events here are greater than 3 hours.

Unit Type	# Events > 3 hrs	Est Lost Time (hrs)
Coiled Tubing Unit	**98**	**2916.0**
CSGCLNOUT	98	2916.0
HCU Unit	**24**	**226.8**
CSGCLNOUT	24	226.8
Total	**122**	**3142.8**

RESULTS

The reduction of solids in the wellbore led an overall decrease in NPT when comparing the HCU versus the CTU which can be seen in Fig. 9.

- ~2.5 CTUs running during the year as compared to 1 HCU, the ratio of events is ~4:1 and total number of hours is well over 10:1.
- As the HCU was trialed in various fields and formations across the Permian Basin it became clear to the operator that the HCU excelled in particular fields, generally those with higher pressure and down-hole complexities.
- The lead author of the paper has found the HCU to be extremely efficient in the Delaware portion of their Permian Basin acreage where depleted areas with cross-flows have caused differential sticking problems in past CTU operations.
- While the HCU has the ability to drill out successfully in each of the fields in the Permian, there are more complex areas, that are exclusive to the HCU application. These areas can be seen in Fig. 10 which shows the operators wells in Lea County were only drilled out by the HCU due to the complexities. In their Eddy County acreage they experienced a large decrease in average days to drill out when comparing the HCU performance to the CTU operations.

ADDITIONAL FINDINGS

Another benefit that the E&P found utilizing DWS HCU is its ability to drill out and instantly install/run the downhole completion equipment without moving off the well or bringing in a workover unit. Having the ability to run production tubing and artificial lift without moving the unit off of the well eliminates the rig up and rig down time, cost of extra rental equipment and reducing the number of custody transitions. This advantage decreased the tubing install by more than half from 1.8 days per well down to 0.75 days per well (Fig. 11), equating in ~$60k in savings per well and a 16% increase in efficiency, and in turn, the ability for wells to start producing at an earlier date.

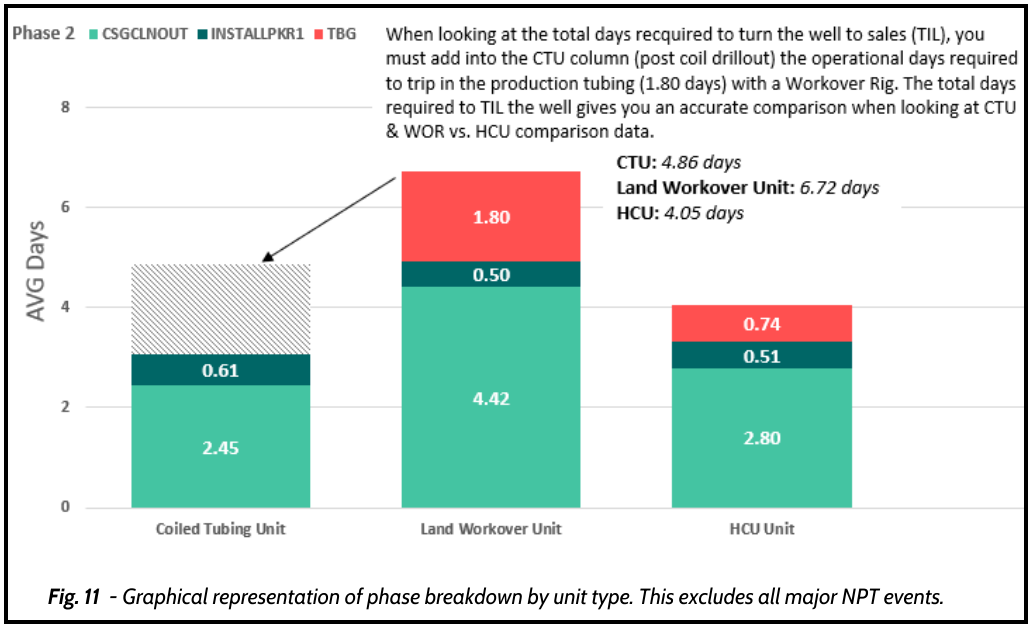

Fig. 11 - Graphical representation of phase breakdown by unit type. This excludes all major NPT events.

Fig. 10 - Bar graph representation of the average number of days to drill out the lateral for each field