Solid Expandable Liner System With Custom Composite Frac Plugs Enable Recovery Of Lost Reserves In The Piceance Basin

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Abstract
Casing integrity failure, whether through parted casing, leaky collars or some other issue, may result in less effective stimulation work due to abandonment of the plug and perf method and/or having to complete through a frac liner. In more extreme cases it could result in lost reserves below the casing failure point. Modern technology has provided a cost effective solution to this problem.

In this case, the operator confirmed parted 4-1/2 inch production casing at 9,761 feet (Fig. 1a) in their northern Piceance Basin acreage. The operator would have to repair the parted casing in order to frac the lower six zones of the well. The plug & perf method for zonal isolation was required to effectively complete the 2,825 foot vertical pay interval. In order to complete the stimulation program, the goal was to repair the short section of damaged casing and restore pressure integrity to the well while maintaining a sufficient inner diameter (ID) to allow composite frac plugs to pass through the repair and set in the base casing’s larger ID below the split. The solution was the use of custom made composite frac plugs in conjunction with a 3-1/2 inch single-joint solid expandable system that was expanded downhole to cover and seal the parted 4-1/2 inch casing.

The 30-ft., 3-1/2 inch solid expandable high-pressure, high-temperature (HPHT) liner system was deployed and expanded in a single trip. This system provided the required pressure integrity to withstand the frac pressures needed in this area. The 3.261 inch drift ID of the expanded solid liner allowed the operator to run custom 3.06 inch outer diameter (OD) composite frac plugs below the repaired section and successfully complete the well.

This installation was a success, as the operator had essentially written off 63% of the well’s reserves due to the casing part occurring above a majority of the pay interval. The operator is now realizing full production from the entire well. Moreover, this single-joint solid expandable liner technology coupled with the special drillable composite frac plugs can be used in any HPHT formation to repair the common issue of damaged casing to allow plug and perf completions to continue.

Introduction
Casing failures are one of the oldest and potentially costliest issues in the oil and gas industry. Immeasurable time, energy and capital have been spent over the years trying to find a solution to this common but debilitating problem. The advent of solid expandable tubular technology has proven to be a cost-effective solution to many casing integrity issues. Originally designed for, among other things, high pressure zones in deepwater environments, solid expandable technology has evolved from isolated applications in extremely expensive cases to the inland development program found in many basins throughout the world. In addition to the improvements in solid expandable tubular technology, engineering advancements in coiled tubing and frac plug technology have also provided answers to historically expensive and perplexing casing failure questions.

As operators utilize solid expandable tubular technology in increasingly creative ways, other limitations present themselves. One example is the ID restriction an operator inherits due to a casing patch/liner. An issue such as parted casing might be resolved but if the casing patch is above a portion, or all, of the identified pay zone then creative engineering is needed to effectively complete the reservoir below the patch.

An ID restriction in a wellbore provides additional frictional pressure loss during stimulation operations. It also provides a bottleneck for proppant to settle and eventually stick tubing and wireline operations. More pertinent to this paper, the ID restriction of an expandable casing patch, though much less than conventional frac liners, prevents conventional frac plugs from passing through the casing patch and setting in the existing casing below the repaired section of pipe; which in this case, left 6 of the 10 identified completion intervals stranded (Fig. 1a). The operator chose not to immediately complete the upper 4 zones in the well as that would have compounded the problem by having to isolate the perforations placed above the casing patch if and when the operator desired to complete the lower 6 intervals.

The remedy to this particular problem would come in the form of a frac plug that could pass through the restricted ID of the expanded casing patch and set in the casing below. Finally, the casing patch and frac plug would have to be able to withstand the high differential pressures typically seen in this portion of the Piceance Basin.
Scenario Description
With 4,000+ wells producing in the basin, the operator has encountered casing integrity issues on several occasions. Past remedies include stimulating past frac liners using sand plugs, trying to contact reserves from nearby wells using large volume frac jobs or simply abandoning the reserves below the casing failure point. These have not proven to be cost effective. The desired solution has always been to repair the casing and continue to utilize the plug & perf completion method.

During the casing integrity test prior to completion, the operator witnessed a rapid pressure loss at 2,500 psi. A magnetic imaging tool (MIT) log was run and identified a radial casing part from 9,761 - 9,762 feet. A cast-iron bridge plug (CIBP) was run at 9,815 feet along with a cement retainer set above the part; the part was then squeezed with cement. After the retainer and cement were drilled out, a pressure test was attempted and failed. Though it’s internal yield strength would have limited completions, a 60-ft, corrugated patch was selected since its final ID would allow existing frac plugs to pass through and set below the repair. However, once the corrugated patch was deployed and installed across the casing split, the pressure test was again unsuccessful. The pressure leak was determined to be at the patch. An injection test was performed and the patch squeezed with cement. Again, the casing pressure test failed. At this point the operator decided to mill the patch and reevaluate available options.

No activity occurred on the well for the next year. Remediation capital was eventually allocated to repair the split but the question remained should the operator attempt the repair or should they salvage what reserves it could through the upper 4 stages. The decision was made to explore repair options. The search began for an HTHP solid expandable casing patch that would have a large enough post-expansion ID for the passing of a composite frac plug and an internal yield strength rating great enough to withstand the high treating pressures in this area. The single-joint, 30-ft. 3-1/2 inch tubing conveyed solid expandable HPHT liner system was chosen since it met all of these requirements. The selection of a patch provided the post-expansion drift ID needed to design the frac plug. Since this specific frac plug did not exist at the time, the operator began working with a vendor that could potentially create the composite frac plug that was drillable and could pass through the single-joint expandable liner, set in the base casing and withstand 300 deg F temperature and a minimum of 6,000 psi differential pressure.

Workflow through Application Design
After a year of no activity, several aspects of the damaged well were reviewed for a second time to reorient the team as to the exact status of the wellbore. A second MIT log was run to determine casing damage incurred during milling operations and to confirm the orientation and length of the split. With a 1-ft., 180 degree radial split from 9,761 - 9,762 feet, the single joint, 30-ft., 3-1/2 inch solid expandable HPHT liner system, with an internal yield strength of 11,560 psi, would become the strongest section of the well once installed. Schematics of the launcher assembly and elastomers were reviewed. Pre-installation activities were discussed and a full installation procedure was written up and approved by the operator’s field and office personnel. During the review of the installation process several topics were discussed at length, including:

- Casing should be pressure-tested below and above the proposed setting depth to make sure there are no unknown leaks above or below the target leak.
- Preparation of the wellbore is critical. The base casing should be clean, free of any obstructions and drilled to ensure that the launcher can be run to the setting depth. This can be done with either a tandem stabilizer assembly or a built-for-purpose drift. In either case, this assembly should be at least (~6 ft) and have a diameter equivalent to the largest OD of the pre-expanded single-joint liner, which in this case is the elastomer seal OD (3.840 inch) which is slightly less than drift of the casing (3.875 inch). It is recommended that the drift assembly is run with a positive blade casing scraper and a bit or mill on bottom and that the drift is run below total depth of where the liner will be set.
- The tubing to convey the single-joint solid expandable liner would be 2-3/8 inch, 4.6 lb/ft., EUE 8rd, P-110 due to depth and the 8,000 psi internal pressure needed to expand the liner. This grade of tubing would also provide adequate joint yield strength if needed.
- Placement of the patch would be corrected back to wireline depth with a GR/CCL tool. Tubing joints will also be counted before and after the single-joint solid expandable liner is run to ensure the setting depth is correct.
- The drilling assembly used to drill out the single-joint solid expandable liner pressure plate will be gauged and consist of a 3-1/4 inch mill, bit sub and 2-3/8 inch P-110 EUE tubing.
- As confidence was building with the single-joint solid expandable liner, focus turned to the composite frac plug that would be needed to pass through the expanded single-joint liner and set in the base casing. The frac plug vendor was given a post-expansion drift ID of 3.261 inches and a base casing drift ID of 3.875 inches, however, the plug would have to set in the nominal casing ID of 4.00 inches and withstand the differential pressure anticipated during frac treatments. The plug would have to be drillable and contain minimum aluminum components. The operator also requested the plug have flow-through capabilities and have a temperature rating up to 300 deg F.
- To determine the pressure rating needed, the operator evaluated 29 frac stages from wells in the same section as the damaged well. Bottom-Hole Pressures (BHP) were calculated, flow-back rates and pressures were analyzed along with surface treating pressures. It was determined the composite plug would need a differential pressure rating of at least 6,000 psi. The operator requested an 8,000 psi rating. Finally, a 3-1/4 inch composite frac plug was modified to 3.06 inches and tested for pressure and temperature capacity. The test revealed 300 deg F was not a problem, however, the plug could withstand pressures above 6,000 psi but the vendor was not comfortable rating the custom plug above a 6K rating.
- The final plug test occurred in a different well to be completed prior to the casing repair. A nearby offset was chosen and completion operations were performed. The lower 6 zones of the offset well were completed with the wireline conveyed custom composite frac plug run on the bottom of the perforation gun. The bottom stage was fracture stimulated, the gun and plug for the next stage was run, the plug set and perforations made. Next, the stage was completed exposing the plug to frac pressure. Following this stage, the next plug and gun was run and the process repeated until the bottom six stages were
completed. At this point the well was flowed back. After a couple of days a service unit was brought in to drill out the test plugs. The custom plugs performed to specification as each one was located exactly where it was placed prior to stimulation operations and drilled without issue.

Now that the single-joint solid expandable liner and plug designs were reviewed and tested, the final design component had to do with drilling out the plugs with the restricted ID of the liner and the production tubing string to be run in the well once completion operations were finished. 1.688 inch OD coiled tubing (CT) would be utilized to drill out the frac plugs above and below the repair. Once all plugs were drilled out, the production tubing string would be landed in the well.

One production string issue that required attention was the need to increase the annular space between the ID of the expanded liner and the OD of the tubing collar. The expanded liner ID of 2.261 inches combined with the 2-3/8 inch EUE collar OD of 3.063 inches warranted the flush-joint tubing option through the liner to mitigate particles packing off in the annular space between the expanded liner and the tubing collar. Therefore, the production tubing string would consist of the following components:

- 1,990 feet of 2-3/8 inch, 4.6 lb/ft L-80 flush-joint tubing (open ended)
- Cross-Over sub
- 9,330 feet of 2-3/8 inch, 4.6 lb/ft N-80 EUE tubing (Fig. 1c)

**Installation and Performance**

To begin the installation process, a service unit was rigged up over the well and 2-3/8 inch, 4.6 lb/ft., P-110 tubing was run in the hole to 9,900 feet to circulate the wellbore. Once consistent, clean returns were coming back the tubing was pulled. The single-joint solid expandable liner was run in the hole along with a cross-over, one (1) - 6 ft. P-110 pup joint and 307 joints of 2-3/8 inch, 4.6 lb/ft., P-110 tubing to place the center of the liner across from the part. A pipe tally was done and a wireline gamma ray tool was run to correlate tubing and patch depth. After a safety meeting, the well was circulated at 1 barrel per minute (BPM) to clean the liner setting ball seat. At this point, the ball was dropped and circulation began until a pressure increase was witnessed, signaling landing of the ball in the liner setting ball seat. Once the ball landed, expansion was initiated by pressuring up the tubing to 8,000 psi. The liner was then expanded with 10,000 lb overpull on the workstring and an average of 6,000 psi hydraulic pressure as the expansion cone slowly expanded the liner from bottom to top. Once the liner was expanded and the launcher assembly was stung out of the expanded single-joint liner, a casing pressure test was done to 4,000 psi an immediate test to see if casing integrity had improved. The 4,000 psi pressure test was a success.

Tubing was pulled, a 3-1/4 inch mill, bit sub and tubing were run in the hole to drill out the pressure plate in the liner. Tubing tagged the pressure plate at 9,775 feet (after correcting to wireline depth), confirming the liner was set at the correct depth. Operations drilled and reamed the pressure plate, then circulated the well while working through the lower portion of the expanded single-joint liner. Confident the pressure plate had been drilled and all components had been circulated out of the wellbore, preparation for stimulation operations began.

A final casing pressure test to 8,500 psi was performed and the casing passed. It was decided to run a 3.25 inch gauge ring through the expanded single-joint liner prior to every perforating run to ensure plugs and guns would not get hung up in the liner. The first gauge ring that was run prior to perforating the bottom interval would not pass through the expanded single-joint liner. After sizing down to 3.15 inches, the gauge ring still would not pass through the expanded single-joint liner ID of 3.261 inches. A 3.20 inch watermelon mill was run in the hole and milled the top of the expanded liner briefly before falling through the rest of the expanded single-joint liner with no issue. Once the frac head was re-installed and tested, the bottom frac interval was perforated; the 2.50 inch guns went through the expanded liner without incident. The bottom stage was completed, a 3.20 inch gauge ring was run through the expanded single-joint liner and the custom plug with perforation gun for the next stage was run without issue. The plug was set and perforations shot. The stage was completed and the process repeated up the well bore for the remaining stages below the repair without incident. The four stages above the expanded liner were then completed using conventional composite frac plugs. With no sand or hang up issues through the expanded single-joint liner during completions, attention was turned to the drill out process.

1.688 inch coiled tubing was utilized to drill out all plugs. After drilling the frac plugs above the liner, the 3.875 inch under reamer could not get past 9,700 feet. It was pulled out of the hole (POOH) and a 3.15 inch mill, motor and CT were run to 9,700 feet to work through the tight spot. The mill was used to clean through the liner, tag the first custom frac plug below the liner and POOH. In preparation to drill out the remaining frac plugs below the liner, the CT bottom-hole assembly (BHA) consisted of a 3.15 inch mill, 3.875 inch under reamer, mud motor and jars. With minimal sand on plugs, the plug location was correct for every plug run below the liner (Fig 1b). At this point the CT was POOH and the well was put on flow back / sales. Once flow back pressures and water rates dropped, a snubbing unit was moved in and rigged up to run production tubing. The production tubing string consisted of 60 joints of 2-3/8 inch flush-joint tubing to be run through the liner and below, followed by 286 joints of 2-3/8 inch, 4.6 lb/ft, L-80 tubing landed in the production tree.

Final wellbore schematic is shown in Fig. 1c.

**Conclusions**

The operator was faced with the issue of casing integrity failure in one of their Piceance Basin wells. It is a problem the operator has faced several times over the course of drilling and completing 4,000+ wells in the basin. The economics of running a frac liner, using slimhole perforating guns and possibly having to fish the liner out of the hole combined with a less effective stimulation did not appeal to the operator. Writing off two-thirds of the wells reserves by only completing the upper 4 zones was also uneconomic. Furthermore, after unsuccessful attempts to repair the well with a corrugated liner and cement squeezes, the well sat dormant for a year as the team re-evaluated how best to move forward. A different expandable liner was chosen due to its solid, single-joint design, high internal yield strength and large post-expansion ID. Custom frac plugs were designed, tested and utilized along with coiled tubing to put the well on full production.

With minimal operational problems throughout the installation of the single-joint solid expandable liner, running of the plugs and drill out/flow back of the well, opportunities for improvement are largely focused on cost. CT worked for this
project; however, moving forward the use of a service unit with slim tubing would be more cost effective to drill out plugs below the expanded single-joint liner.

Ultimately, the operator was able to repair a familiar issue in a way that enabled full recovery of the wells reserves. This was a first for the operator, considering the high treating pressure and location of the split. The plug and perf method had not been an option in the past, however, moving forward the operator has a cost effective solution that enables the use of plugs and assures the operator that effective stimulation of the pay interval is still possible.

Solid expandable tubular technology, engineering advancements in frac plug design and CT advancements have given the O&G industry tools that were not available in the past. Supplemental to the case outlined in this paper, application of these technologies could involve, but certainly not limited to, multiple parts in a casing string, sliding sleeve bypass or isolation of perforations that are no longer necessary.

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References
Figure 1a – Wellbore schematic with casing part and pay zones identified.

Figure 1b – Single-joint solid expandable liner installed with frac plug type and location post-stimulation.

Figure 1c – Final completed wellbore with production tubing landed.