Abstract
Horizontal shale completions require multi-stage high-pressure hydraulic fracturing stimulation treatments in order to deliver commercially viable production in low permeability reservoirs. Unconventional shale plays, such as the Eagle Ford and Haynesville Shale, often require stimulation treatments that must be implemented in high pressure and high temperature (HPHT) conditions. Typically, these wells are completed with long casing strings, and it is critical that these monobore casing strings withstand high injection pressures as well as maintain mechanical integrity during thermal contraction/expansion. So what happens when the pre-frac casing pressure integrity pressure test fails? What is the “fix” that will allow treatments to be pumped at high pressure and rate? How will frac stages be isolated during the completion? Typically, remediation techniques have included everything from casing patches and expandable casing to coiled tubing completions. Unfortunately, these solutions can have pressure limitations, and in addition, can be cost prohibitive.

The authors of this paper will discuss how design of a 4-in. tie-back string with flush joint connections equal to the properties of the casing was capable of repairing a 5-1/2-in. monobore production casing that experienced extensive casing failure. The extremely small annular tolerance did not allow a conventional packer assembly or cementing for pressure isolation; thus, swellable packer technology was used to anchor the casing in place. A special flow-thru frac plug was designed so that it could be pumped through the 4-in. tie-back casing and set in the 4-1/2-in. lateral, allowing a plug-and-perf fracture completion to be performed. The stimulation treatments were pumped to completion and demonstrated 1), that the pressure isolation integrity of the casing system was satisfactory; and 2), that the flow-thru frac plugs could maintain isolation between stimulation treatments. This wellbore was in the Eagle Ford Shale. True vertical depth (TVD) was ~13,000 ft, bottomhole temperature (BHT) was ~325°F with a 0.95 psi/ft frac gradient, and surface pressures exceeded 10,000 psi during the stimulation treatments.

Introduction
The Eagle Ford shale completions, along with most other unconventional plays, require multi-stage high pressure hydraulic fracturing stimulation treatments to produce at economically viable production rates. Even though treating pressures stay well below the mechanical limits of the tubulars, casing failures can still occur. Many of these failures are attributed to the cycling of high pressures as well as extreme temperature fluctuations that occur in hydraulic stimulation treatments. These pressure and temperature conditions create large forces for the wellbore to endure. Accounting for tension, compression, buckling and ballooning, and thermal effects makes wellbore design critical. In this case study, a coupled connection failed in the vertical section above the crossover between the 5-1/2-in. and 4-1/2-in. production casing. The well was repaired by placing a 4-in. liner, which was anchored in place using swellable packer technology, across the casing failure. A flow-thru frac plug then was developed that would travel through the smaller 4-in. ID liner and could be set in the 4-1/2-in. lateral to isolate each section between frac stages. This repair allowed for the successful stimulation of multiple stages of casing fracture treatments, enabling the well to be produced economically.

Challenges Created by Casing Failure
Certain failures result when exceeding the physical properties of the casing, though in this particular instance, a metallurgical defect yielded the casing at a coupled connection. This particular wellbore used the most common wellbore configuration in the Eagle Ford at the time; i.e., a 5-1/2 inch 23 lb/ft P-110 casing in the vertical wellbore and 4-1/2 inch 15.1 lb/ft P-110 casing below the kick-off point into the horizontal section. The casing experienced a failure at 9208 psi or 64% of burst pressure (14420 psi) after pumping 1050 bbls total slurry on stage one.
No immediate pressure change was observed on the annulus during the failure. A spinner and temperature survey, performed while pumping, revealed the hole in the casing to be at 3319 ft. A plug was set below the known hole in order to isolate pressure and perform a subsequent workover. The casing was shot off 30 ft below the parted section to recover the split collar (Figure 1). Since there was minimal cement where the casing parted inside the surface casing, a 17,000-psi-rated external casing patch was run to remediate the failure. However, upon further investigation into the coupling failure as well as remediation attempts from other operators on the same coupling connections, subsequent failures in the remediated wellbores were noted. This information rendered the 5-1/2-in. string unfit for a high-pressure, multi-stage completion.

![Pressure Anomaly](image)

**Figure 1 — Frac Data During Casing-Collar Failure**

**Figure 2 — Recovered 5-1/2 in. Casing Collar (erosion in split caused during fluid injection).**

### Casing Repair

Many remediation techniques were investigated; these included casing patches, expandable casing, cased-hole ball and sleeves, and even, coiled-tubing completions. These techniques provided few options that could withstand working frac pressures over 10,000 psi without compromising the completion design. A solution was needed that would provide casing-pressure integrity without limiting the number of “plug-and-perf” frac stages that could be pumped due to any type of wellbore restriction.
The best solution was to install a 4-in. tie-back string into the wellbore that would be anchored using swell packers just above the 5 1/2-in. to 4 1/2-in. casing crossover. This would allow the lateral to be completed with minimal restriction at the point of the tie-back and would allow an acceptable injection rate. It also would minimize risk while running perforation guns and frac plugs. In order for this technique to be viable, a set of swellable packers engineered for this specific application and a special flow-thru frac plug that could pass through a small restriction, yet set in a larger ID pipe to provide isolation between frac stages, had to be developed.

The largest tie-back string that could be used in 5-1/2-in. 23#/ casing with an inside diameter of 4.67-in. (drift 4.545-in.) while creating minimal restriction while completing the 4-1/2-in. lateral was 4.0 in 10.7# P-110 tubing (ID = 3.476-in., drift = 3.351-in.) using a flush connection. While researching flush-joint pipe connections, it quickly became apparent that most flush-joint connections had down-graded physical properties that would provide little or no safety factors under normal completion conditions. A special threaded and coupled (T&C) premium clearance connection was found (Klementich, et al, 1995), which would provide the same tension and compression properties as the pipe itself (Figure 3). This connection would also allow for 100% of the pipe’s 12,610 psi burst and 11,060 psi collapse pressure ratings to be used for calculating fracture-stimulation design pressures.

<table>
<thead>
<tr>
<th>Pipe Parameters</th>
<th>Connection Parameters</th>
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<tr>
<td>Size (OD) - inches</td>
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<tr>
<td>Nominal ID - inches</td>
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<tr>
<td>Make-up Torque (ft-lbs)</td>
<td>-</td>
</tr>
<tr>
<td>Yield Torque (ft-lbs)</td>
<td>-</td>
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</tbody>
</table>

**Figure 3 — Special Clearance Threaded and Coupled Connection with 100% of Pipe Ratings**

**Tie-Back String Anchor Design**

Having a tight tolerance between the tie-back string and original casing meant that no mechanical-set packers could be used to isolate the string without creating a restriction in the inside diameter of the string. Such a restriction in the wellbore would have meant that a “plug and perf” operation could not be completed successfully. The small clearance of the casing/casing annulus also posed a high risk for a cementing operation because of the resulting lift and friction pressures that would be caused by attempting to place cement in the annular space between the 4-in. tie-back string and the 5-1/2-in. production casing. Pursuing alternative options pointed toward using existing technology that could be adapted in a new or uncommon application; i.e., namely, using swellable packer technology (Kennedy et al. 2005) to create an anchor packer for the tie-back string (Figure 4). The concept seemed possible given the wellbore configuration, although it had never been done under these conditions. The swellable packer seal would have to sustain high-pressure-and-temperature cycling effects of the fracture stimulation treatment, while maintaining its anchoring force. Due to the HPHT conditions of the wellbore and uniqueness of the application, extensive modeling was necessary to ensure that the swellable packer design would provide sufficient anchoring force to hold the tie-back in place throughout the fracture stimulation treatment.

**Figure 4 — Swellable Isolation Packer**
Multiple series of tubing movement calculations were performed using several different fracture stimulation scenarios. This would allow for modeling of the forces the swellable packer would have to withstand given each scenario. Each fracture-stimulation scenario contained different parameters for surface treating pressure, pump rate, fluid weight, sand-laden fluid density, etc. Additionally, tubing movement software had seldom before been used to attempt to simulate a swellable packer as a tie-back so new modeling techniques had to be developed given the current limitations of the software. These techniques further enhanced the accuracy of the simulation. Figure 5 below illustrates the results of a tubing movement simulation performed on the tie-back string. Once a working range of forces for the various frac scenarios was simulated, the design process for the swellable packer design began. Several different swellable packer designs were developed, and each design had corresponding differential pressure and anchoring force ratings (Figure 6). The swellable packer designs were matched to the different fracture simulation scenarios; however, during this process it was discovered that the tie-back casing selected for this application was only available in a specific length. Since each swellable packer is bonded to the parent casing string (the tie-back casing in this case), and the length of casing that could be obtained limited the possible lengths of the swellable packer element, it was decided that multiple swellable packer elements would be required. A final swellable packer design was based on the maximum fracture stimulation parameters expected during the treatments; thus, the tie-back seal should not fail under the worst of conditions.

![Figure 5 - Sample Tubing Movement Simulation](image)

![Figure 6 - Swellable Packer Differential Pressure Simulation](image)

After extensive modeling and careful planning, a system of oil swellable packers was built and installed to anchor the tie-back string at the 5-1/2-in. X 4-1/2-in. crossover. Three swellable packers (4-in. parent casing x 4.45-in. OD x 20-ft long) were stacked on top of each other just above the casing crossovers to maximize the anchoring affect and provide sufficient differential pressure. A bridge plug was set below the crossover to allow weighted diesel to be slowly circulated around the packers in order to swell and set the packers. Once this was done, the packers were left in the wellbore and allowed to swell for three weeks (Figure 5). Multiple pressure tests on the system performed after the swelling process had concluded indicated that the tie-back seal had good pressure integrity.
Frac-Plug Design
Before implementing a 4.0-in. tie-back string, a flow-thru frac plug had to be designed and tested for this application. This meant that a plug would have to be developed that would pass through the 4.0-in. tubing, pumped down, and set in the 4.5-in. lateral for the completion. The plug would preferably be of the flow-thru type with a 10,000 psi, 350°F rating. The only existing extended-range plug on the market would not work, because it was not drillable horizontally with coiled tubing (stainless steel plug) or did not allow for flow-thru. This created the challenge to design and test a custom plug for this application. The plug had to be designed to be wireline- or coiled-tubing-deployed, with a long rubber element, with extended-reach cast-iron slips, and with an aluminum flow-thru body with a clutch system to interlock the plugs during drillout. The plug also was to be fitted with wear rings to prevent lateral wear and premature deployment during vertical wireline operations through restrictive tubulars or during pump-down operations (Figure 8).

The flow-thru frac plug subsequently developed was lab tested successfully in 4.5-in. 15.1# P-110 and demonstrated that it was robust with sufficient pressure-differential ratings for Eagle-Ford completions. While waiting for the tie-back installation on the case well, the plug was field tested on a well with severe dog-leg issues. The curve of the horizontal wellbore prevented conventional plugs from passing through, and a slim-hole flow-thru frac plug was needed (Blevins et al., 2011).

Special consideration had to be given to the drilling out of these plugs because of the wellbore configuration. Underreamers were designed for coiled-tubing drillout applications as well as bi-centered mills. The concern was that if a conventional mill were to be used, it would be under-sized to fit through the 4.0-in. tubing and leave behind plug debris in the lateral, which could cause the coiled tubing to get stuck. The use of an under-reamer would allow minimal risk during the coiled tubing drillout operations and effectively drill out the plugs. As anticipated, the plugs were drilled out without issue.

Tie-Back Installation Repair
A bridge plug was run into the well and set below the 5½-in. to 4½-in. casing crossover. This would provide a bottom to hold the swelling fluid in place during activation of the swellable packers. The tie-back string was successfully run and landed on the 5½-in. to 4½-in. casing crossover. The tie-back string was picked up, and the swelling fluid was circulated into the wellbore to begin the swelling process. The tie-back string was lowered back down to rest on the casing crossover at +/– 12,300 ft. MD. The swellable packers were given three weeks to fully expand, and pressure integrity tests were conducted to ensure that the seal of the swellable packer tie-back anchors was secure. The bridge plug was milled out with coiled tubing prior to the running of these tests, and the wellbore was cleaned out prior to the stimulation treatment process. “Plug- and-perf” completion operations were implemented using the slim-hole flow-thru frac plug, and the fracture stimulation treatments were successfully pumped through the tie-back assembly. No increased pressure was experienced on the annulus between the parent casing and the tie-back string during the fracture stimulation treatments. After all frac stages were completed, the flow-thru frac plugs were drilled out, and the well was placed on production. Figure 7 shows the final wellbore configuration.
Fracture Stimulation Considerations

Fracture treatment calculations (Figure 10) were performed to determine the wellhead treating pressures that could be expected for various injection rates, given the 3.476-in. inside diameter restriction of the vertical tubular tie-back string. It was determined that a treatment rate of 35 to 40 bbl/min. could be used for the completion, and this would provide a safe working range around the 10,500-psi wellhead treating pressure (WHTP). As such, only 4 perforation clusters were used to ensure diversion, and the perforation scheme was modeled with a maximum rate of 35. Rates above 40 bbl/min. were expected during the sand-laden fluid portions of the treatments because of the increased hydrostatic pressure that could occur. Acid-soluble cement was used to isolate in the lateral and minimize the effects of near-wellbore tortuosity (Stegent, et al. 2010). 1,000 psi was estimated for the total pressure expected for the perforation and near wellbore friction, while a frac gradient of 0.97 psi/ft was used to calculate bottomhole treating pressure (BHTP).

Stimulation Treatment Summary

The subject well was fracture stimulated with treatment designs similar to those pumped on the offset wells. The proppant and fluid volumes pumped were similar on all frac stages, but the injection rates during the pad were reduced slightly due to the higher pipe frictions caused by the smaller ID tie-back casing string. The swellable packer assembly maintained good pressure integrity and isolation between the 4-in. tie-back and the 5-1/2-in. casings during the pumping of the frac jobs. The slim-hole flow-thru frac plugs were set without issue, and all appeared to provide adequate isolation between frac stages, as all stages were pumped to completion.

Figure 9 illustrates the surface location of the subject well relative to five of the nearest offset wells along with the comparative equivalent cumulative productions. The production data were obtained from a public database and have not been normalized other than by converting the liquid hydrocarbon production into a gas equivalent value (5.8 Mscf/stb). The production from the subject well was comparable to the offset wells, demonstrating that the casing repair was effective and had allowed the well to be properly fracture stimulated.

\[
\text{WHTP} = \text{BHTP} - \text{P}_{\text{hydro}} + \text{P}_{\text{pipe}} + \text{P}_{\text{perf}} + \text{P}_{\text{nwb}}
\]

Where:
- \( \text{WHTP} \) = Wellhead Treating Pressure (psi)
- \( \text{BHTP} \) = Bottom Hole Treating Pressure (psi)
- \( \text{P}_{\text{hydro}} \) = Hydrostatic Pressure (psi)
- \( \text{P}_{\text{friction}} \) = Pipe Friction Pressure (psi)
- \( \text{P}_{\text{perf}} \) = Perforation Friction (psi)
- \( \text{P}_{\text{nwb}} \) = Near-Wellbore Friction/Tortuosity (psi)
Conclusions
The repair of the damaged wellbore was a success which can be attributed to adapting existing technology to a new application. The anchored tie-back string with swellable packers sealed off the failed casing, allowing for the stimulation of the well, which was required for its successful completion.

- This success resulted from extensive design modeling and tubing movement models that were capable of calculating the data required for the manufacture of a tie-back casing design with swellable-packer anchor configuration.
- The special pump-down flow-thru frac plug was designed with a reduced OD, allowing it to pass through a restricted tubular and to create isolation during stimulation by being set in a larger tubular. These plugs were successfully drilled out post completion.
- The stimulation treatment was successful, and the modeling of the tools as well as the conceived rates and volumes necessary to provide an effective stimulation proved to be appropriate for the design and execution of the operation. The post stimulation data and production information corroborated the effectiveness of the remedial operations.
- The tie-back casing-string design discussed in this paper allowed for the salvage of a completion that was potentially uneconomical. The completion also was accomplished with a minimal amount of risk.

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References
Kennedy, G. Lawless, A., Shaikh, K., and Alabi, T.: “The Use of Swell Packer’s as a Replacement and Alternative to Cementing”, paper SPE 95713, Presented at the SPE Annual Technical Conference and Exhibition, 9-12 October, Dallas, Texas, 2005

SI Metric Conversion Factors
bbl × 1.589 873 E − 01 = m³
°F (°F − 32)/1.8 = °C
psi × 6.894 757 E + 00 = kPa
ft × 3.048* = E − 01 = m
lbf × 4.448 222 E + 00 = N
in. x 2.54* = E + 00= cm
*Conversion factor is exact