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Resin Sealant Remediates Annular Gas Flow to Surface Allowing Completion of Four Colorado Wells

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Abstract

Four wells drilled in Weld County, Colorado exhibited annular gas flow after cementing the production casing. The Colorado Energy & Carbon Management Commission enforces bradenhead pressure restrictions dependent on the well's setup. These wells displayed build up pressure above 200 psi prior to completion and therefore required remediation to limit buildup pressure to less than 50 psi before proceeding.

Conventionally, a cement slurry is used for remediation but challenges arose in the ability to permeate into restricted flow paths indicated from cement bond log analysis. To maximize penetration into void spaces from micro-annuli and channels, a particle laden free epoxy resin sealant was chosen. Each remediation was able to initially inject 1.5 to 2 bbl of resin and prior to shutting in the well with approximately 3000 psi, 2 to 2.5 bbl of resin through one to three hesitation squeeze cycles.

Further review into remediation took place with focus on where to squeeze in relation to the source of gas, cement top & quality, and previous casing shoe. An assessment of the epoxy resin against cement was analyzed with emphasis on ability to penetrate into tight pathways, seal hydrocarbon flow, and resist against stresses seen while completing and producing the well.

With proper planning, each 4 bbl squeeze of resin was successfully executed through balance plug, hesitation squeeze method. Each squeeze reduced the annular gas flow to acceptable standards to allow completion of all four wells without the need for additional remedial operations. The use of resin as a sealant has proven to be an effective and economical solution against annular gas flow to surface.

Introduction

Oil and gas wells drilled today will penetrate through multiple types of formations that consist of diverse fluids, temperatures, and pressures. Ability to isolate these formations must be accounted for in order to drill, complete, and produce hydrocarbons safely and efficiently. Both operators and service companies understand that keeping these formations from communicating with one another or to surface in an uncontrolled fashion is critical. While placement of cement on primary jobs is still the most effective and economical method of providing long-term zonal isolation, there are a myriad of reasons as to why a cement job may not achieve its desired effect, whether immediately after placement or later on throughout the life of the well. In these cases, when there is a risk of communication between zones, some sort of remedial treatment is often required to provide the zonal isolation needed to safely operate, complete, and produce the well.

Historically, many methods have been employed to try to provide a barrier as part of or in conjunction with the primary cementing job. Examples of these methods, but not limited to, are discussed below.

- API Standard 65-Part 2 (December 2010), offers comprehensive guidance to operators and service companies for optimizing drilling fluid, cement, and spacer fluid properties and placement techniques to ensure the best chance of success using set cement as a barrier against annular flow.
- Nelson and Guillot (2006) also more thoroughly discuss the importance of centralization to ensure optimal mud removal prior to cement placement.
- Mechanical barriers have also been used. Laws et al (2006) described the use of annular packers made from swellable materials in conjunction with cement to improve zonal isolation on high-pressure gas wells in Oman; however the success of these materials is dependent on placement, frequency, and elastomer reactivity to annular fluids it comes in contact with.
- Carragher et al (2023) describes a technology that improves zonal isolation at liner tops with a pup joint externally coated with bismuth. As the liquid bismuth melts from a thermite heat source, it settles into void spaces and potential flow paths then re-solidifies. The success of this method is dependent on placement, as it only functions as intended if the bismuth coated joint intercepts the flow path. It will not correct possible channels or flow paths that are on the exterior face of the cement sheath in contact with the formation wall or previous casing.

If zonal isolation is not successfully established during the drilling and cementing processes, or if communication is established through the set cement sheath later in the life of the well, remediation can be exceptionally difficult. Cowan (2007) analyzed 137 wells in the Permian Basin with attempted traditional cement squeezes to repair leaks and found that the rate of success of cement squeezes is relatively low – only 34% of the wells were repaired in one attempt and 26% of the wells were never successfully repaired even after multiple attempts. Repairing a primary cement job that is compromised through mechanical failure, debonding, gas migration, or poor mud removal can prove to be even more difficult due to the very small gaps for fluid to flow. In the same paper, Cowan (2007) discussed the concept of an injectivity factor that corresponds to the size of the leak path. The injectivity factor is calculated as the injection pressure in psi divided by the pump rate in barrels per minute (bpm). As the injectivity factor increases, it becomes more difficult to seal the leak path with conventional materials due to the relative size of the leak path. Cowan (2007) concluded that any squeeze with an injectivity factor above approximately 2500 would require an alternate solution to a conventional cement squeeze. If not altered, the large particle size of conventional cement will not penetrate into the small paths and voids that need to be sealed. The cement will bridge off early and form a cement cake that while squeezing can provide a false indication of a seal due to a flat-line pressure response but actually end up failing immediately by not being able to fill and block all pathways or overtime break down due to properties of the dehydrated cement sheath. Even cement with just micro particles can be limited in penetrating gaps of less than 300 microns in width (Wasnik et al, 2005). However, a particle free epoxy resin sealant can be applied in order to maximize injectivity.

Resin sealants have a long history in the oil and gas industry, with its earliest commercial applications dating back to the 1940's (Sonnier, 2018). Resin technology for oil and gas use has advanced thanks to simultaneous development for other industries. Formulations are now adjusted to the wellbore needs with modifications to rheological profile, thermal stability, compressive strength development, tensile strength, elasticity, chemical resistance, adhesion, shear bond, and exotherm & shrinkage control. Although, there are a few drawbacks to using resin. Resin can be challenging to mix, as its viscosity is often higher than that of commonly used Portland cements, and the cost of resin is significantly higher on a volume basis when compared with conventional or micro-cements (Sonnier, 2018). The success documented by Jones et al (2013) shows that resin is an ideal candidate for remediating wells where the primary cement job has failed to provide adequate zonal isolation due to its solids-free nature and ability to penetrate small paths that allow for gas migration.

Problem Background

The state of Colorado implemented new regulations in late 2020 that tightened requirements on annular casing pressure monitoring and placed limits on bradenhead pressure that would be allowed without remediation. The new rules states that the bradenhead pressure action threshold is calculated as 30% of the true vertical depth (TVD) in feet of the surface casing shoe, expressed in pounds per square inch gauge (psig), i.e., if a well has a surface casing shoe set at 1000 ft, then the bradenhead pressure required for remediation would be at 300 psi (CECMC, 2023). The Colorado Energy and Carbon Management Commission (CECMC) is the regulatory agency charged with enforcing these rules, and as such they are also able to set further restrictions on bradenhead pressure in the public interest depending on the area where the well is drilled.

As part of their normal operations, the operator involved in this study drills and completes wells targeting the Niobrara formation in the Wattenberg gas field in Weld County, Colorado. The typical well design is to set 9 5/8", 36 lb/ft surface casing in a 12 1/4" open hole at approximately 1600 ft, approximately 100 ft into the Pierre Shale. 5 1/2" 20 lb/ft production casing would then be set in an 8 1/2" open hole to approximately 21,000 ft measured depth and 7100 ft TVD. Each surface casing had cement coverage up to surface and on the production casing, a top of cement around 2300 ft. This was high enough to cover all potential hydrocarbon zones but low enough to leave approximately 700 ft of open hole which should it be required, allow room for remedial work to occur. These wells were subject to additional restrictions on bradenhead pressure beyond the statewide rule and if there was more than 200 psi on the 5 1/2" x 9 5/8" annulus at any point prior to completion, the CECMC would not allow completion operations to take place until pressure on that annulus was reduced to below 50 psi. Four of these newly drilled wells at some point showed bradenhead pressure above 200 psi prior to completion and therefore required remediation.

Table 1 – Summary of Bradenhead Pressure on Wells

Bradenhead Pressure	Well 1	Well 2	Well 3	Well 4
Maximum Recorded	370 psi	219 psi	248 psi	276 psi
Action Threshold	480 psi (30% of Surface Casing TVD)			
Additional Restriction	200 psi (Prior to Completion Operations)			

Treatment Design

The first step in remediation was to try to identify the source or path through which the gas was flowing. Cement bond logs (CBLs) were performed on all four wells. The CBLs showed cement coverage to approximately the expected target top of cement, but the CBLs did not show good uniform cement sheath near the top. All four wells showed patches near the top that exhibited poor bond of cement to casing and formation, and possible a micro-annulus on either side of the cement sheath. Figure 1 and 2 are provided as an example of the first well that was remediated. Figure 1 reveals the CBL response without pressure on casing whereas Figure 2 shows with pressure.

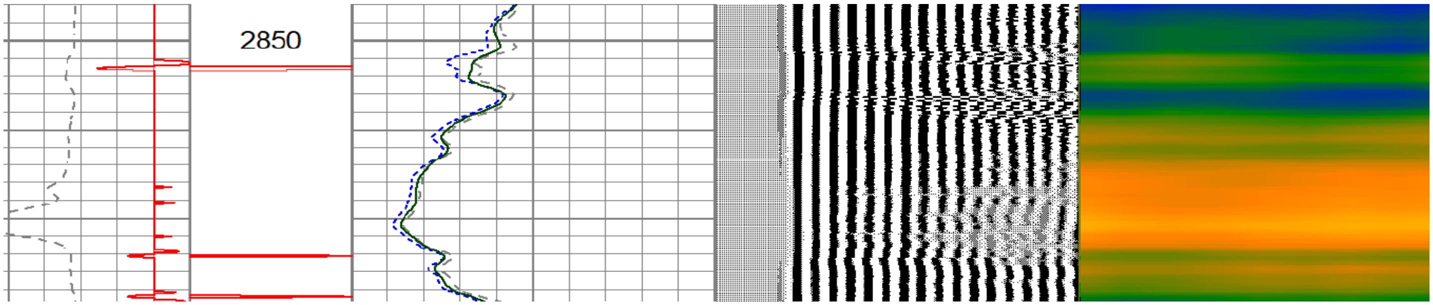

Figure 1 – CBL Snip of Perforated Interval without Pressure Applied to Casing while Logging

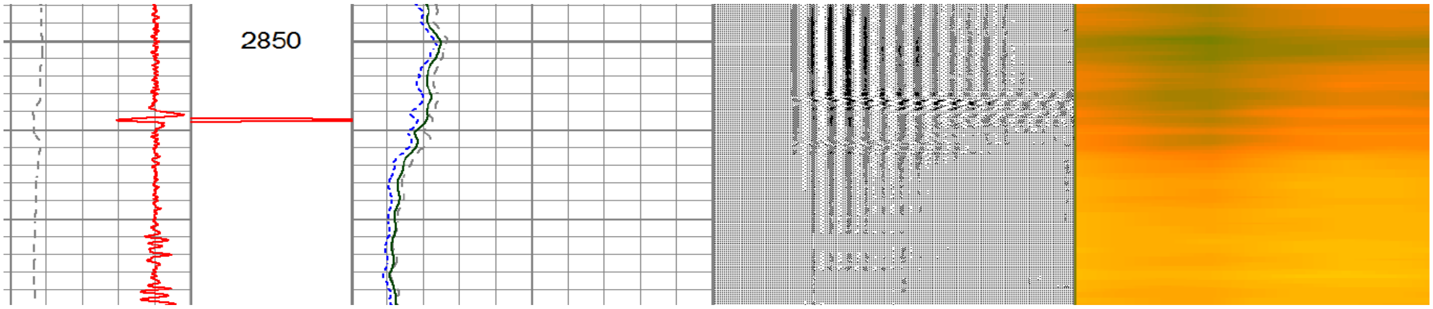

Figure 2 – CBL Snip of Perforated Interval with Pressure Applied to Casing while Logging

The CBL with pressure applied to the casing while logging showed an improved acoustic response, indicating at least a micro-annulus formed between the casing and cement. This micro-annulus was most likely the pathway for gas to be communicating from a deeper hydrocarbon bearing zone to surface. As these were very small voids to fill, with likely very low injectivity, the team elected to proceed with perforating a six foot interval of the production casing and into the cement sheath. A squeeze with a small amount of resin (4 bbl) would be used to seal off the voids and paths.

The resin properties tested specifically for this job included thickening time and crush compressive strengths. The resin sealant comprised of a three part mixture: base epoxy resin, amine hardener, and varying amounts of accelerator depending on the bottom hole temperature. With water as the well fluid, weighting agents were not required leaving the mixture at 9.3 lb/gal and particle free. To prepare the resin mixture in the lab, the base resin and hardener were sheared in a Waring blender jar for five minutes at a shear rate just high enough to maintain a vortex. The accelerator was then added to the resin-hardener mixture and sheared at the same rate for another five minutes. A thickening time test was then performed at the bottomhole circulating temperature and pressure determined from the squeeze cementing schedules listed in the API Recommended Practice 10B-2 (April 2019). The thickening time was determined from the time to reach 70 Bearden units of consistency (Bc) with a modified paddle that had the outside plates removed. Represented by Figure 3, the paddle was modified to account for how resin builds viscosity over time versus a cement slurry. The modified paddle provided less surface area and thus drag force which allowed the thickening test time to be extended out further.

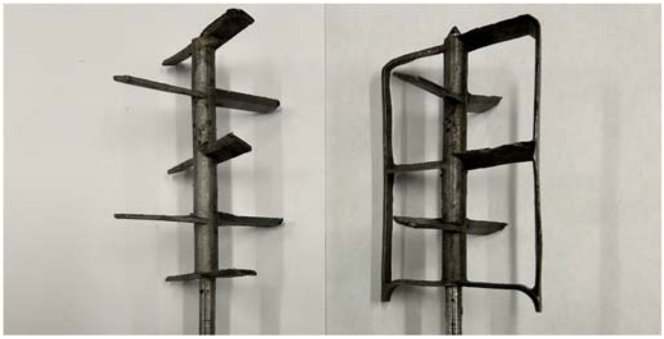

Figure 3 – Modified Paddle vs. API Paddle for Thickening Times

Per API Recommended Practice 10B-2 (April 2019), a cement slurry has reached a consistency deemed sufficient enough to make it unpumpable (e.g. 70 Bc or 100 Bc). Whereas with resin, it is still pourable and pumpable. Figures 4 and 5 reveal consistency of resin at 70 Bc vs. cement at pump off.

Figure 4 – Resin at 70 Bc

Figure 5 – Cement at Pump Off

Compressive strengths were measured from crushing two-inch cubes with a digital hydraulic press. Three cubes were crushed after curing for 24 hours in a water bath at downhole temperatures. Epoxy resin is highly elastic and if not confined will deform while being crushed as represented by Figure 6 at the start of crush and Figure 7 at the end of crush, right before failure. For this reason, compressive strengths are recorded not only at failure but once the cube has deformed by 10% and 20% of the original length. The resin mixture used for the first job measured on average 3165 psi when deformed by 10%, 5354 psi when deformed by 20%, and 7086 psi at complete failure. The cubes are to represent the time needed for resin getting into small voids from micro-annuli and channels to build strength. Resin inside larger spaces such as the casing will cure quicker due to the thermal mass effect, e.g., resin in a 5-gallon bucket will cure quicker vs. resin in a cup.

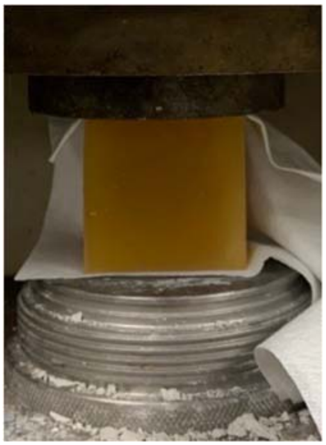

Figure 6 – Crush Start

Figure 7 – Crush End

Job Execution

The execution was nearly identical for all four wells that were remediated using resin sealant. The wells were prepared by running in with wireline to perforate the desired six foot interval. A drillable cast iron bridge plug was set below the bottom perforation within 20 ft to allow resin a base to rest on. Resin is immiscible and depending on the density of fluid it is surrounded by will either strive to float or sink. Given the well was filled with water, a lighter particle-free fluid, the resin will slump down and displace the water up until it reaches the top of the bridge plug. For this reason, the 2 3/8” tubing string used to circulate the well clean and place the resin was not set at the bottom perforation but just above the bridge plug by 10 ft.

A cementing pump truck was used to prepare the resin. As the volume to be placed in each well was only 4 bbl, the entire volume was batch mixed in a displacement tank outfitted with an agitator. The base epoxy resin was taken to location in 1 tote. The tote was lifted above the pump truck with a forklift and gravity fed into the displacement tank until empty. The amine hardener was added from pails in 4 gallon increments to the resin then allowed to mix for ten minutes. While mixing, the high-pressure lines were tested. After a successful pressure test and acknowledgement of ready to go downhole with resin by all operation personnel, accelerator was added to the resin-hardener mixture from 1 gallon jugs then allowed to agitate for five minutes prior to pumping. The accelerator was adjusted for each job such that the total thickening time to 70 Bc was 3 to 4 hours. Figure 8 shows the resin being homogenized in the displacement tank outfitted with a paddle agitator.

Figure 8 - Resin Mixing on Cementing Pump Truck

After the balanced plug of resin was placed, the tubing was slowly pulled out of the resin at less than 30 ft/min. Once the 2 3/8” tubing string was at a safe distance above the resin plug, the work string was circulated clean. Then, the annular preventer was closed and resin was squeezed through the perforations and into the 5 1/2" x 8 1/2" annulus. A hesitation squeeze method was used on all four wells, with between one and three hesitations on each well. The initial pressure applied was between 2000 and 3000 psi. The initial leak off was monitored and once pressure dropped below 1500 psi, the pressure was increased again until final squeeze pressure was maintained. The squeeze was considered complete when no pressure leak off was seen with 3000 psi surface pressure. This typically required the injection of 2 to 2.5 bbl of resin past the perforations. The well was then shut in with pressure until the resin was cured in full.

Table 2 – Summary of Treatment on Wells

Well Details	Well 1	Well 2	Well 3	Well 4
Top Perforation	2860 ft	2334 ft	2784 ft	2384 ft
Bottom Perforation	2866 ft	2340 ft	2790 ft	2390 ft
BHST	128 °F	110 °F	122 °F	111 °F
Resin Vol. Placed	4 bbl	4 bbl	4 bbl	4 bbl
Resin Vol. Injected	2.0 bbl	2.1 bbl	2.5 bbl	2.3 bbl
Hesitations	1	3	3	3
Shut In Pressure	3045 psi	3000 psi	3100 psi	3030 psi

Results

Compressive strength development was sufficient enough to allow for drill out of the remaining resin left inside casing 24 hours from the time of mixing but the operator waited a minimum of four days prior to releasing pressure on the well. The drill out was attempted with both a conventional tricone bit and motor & mill combination. Both successfully drilled out the resin which due to its mechanical properties required more drill out time over a conventional cement plug. The motor and mill combination were able to drill up to 80 feet per hour whereas the tricone bit was able to achieve 40 feet per hour. Unlike the motor and mill combination, the tricone bit left a resin film on the inside wall of the casing which made subsequent operations more difficult. After drill out, the casing was pressure tested and the resin was able to maintain a seal. As a precaution, the operator ran a casing patch to cover the six foot perforation interval to ensure they would not leak during subsequent hydraulic fracturing operations.

The operator monitored the annular pressure for approximately two weeks prior to performing another bradenhead pressure test to submit for state approval to allow for well completion. As revealed with Table 3, all four wells had a significant reduction in annular pressure and were brought back within CECMC regulations to allow for well operations to continue.

Table 3 – Summary of Outcome on Wells

Bradenhead Pressure	Well 1	Well 2	Well 3	Well 4
Maximum Recorded	370 psi	219 psi	248 psi	276 psi
After Drill Out	4 psi	6 psi	19 psi	0 psi
Time Before Drill Out	18 days	5 days	4 days	8 days

At this time, only Well 1 has been completed and placed into production. Prior to the hydraulic fracturing treatment, the annular pressure build was 4 psi. After the fracturing job, the annular pressure only increased up to 18 psi, which is still within the CECMC's limits to allow for production to continue.

Conclusions

From the results presented here, it is evident that epoxy resin is a viable option as a sealant for restoring well integrity in situations where Portland cement is not appropriate. The solids-free nature of resin allowed penetration into voids where cement particles could not reach or seal. Resin proved to be capable of mitigating annular gas flow with minimal volume required. A remedial squeeze with resin is simple to execute from an operational standpoint with results that are clearly repeatable. The completion data from Well 1 suggests that a small volume of resin can perform as a long-term sealant, by withstanding the stresses seen from the cyclic loads of the horizontal hydraulic fracturing treatment.

Acknowledgments

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Nomenclature

psi = *pound-force per square inch*
bbl = *barrel*
API = *American Petroleum Institute*
bpm = *barrels per minute*
TVD = *True Vertical Depth*
psig = *pound-force per square inch gauge*
ft = *feet*
CBL = *Cement Bond Log*
lb = *pound*
gal = *gallon*
Bc = *Bearden units of consistency*

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