FROM ZONE ABANDONMENT TO RESTORING WELLBORE INTEGRITY: MODERN EPOXY RESIN TECHNOLOGY WELL REMEDIATION CASE STUDIES

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ABSTRACT

This paper discusses Permian Basin examples of a modern epoxy resin system that is compatible with most water- and oil-based wellbore fluid systems. Its unique mechanical properties and resistance to contamination make it a good solution for issues too complex, costly, or difficult to resolve using traditional remediation methods and materials. These case studies include the following uses of this epoxy resin: 1) as a squeeze treatment to repair a well production casing leakage, re-establishing casing integrity, and allowing the planned stimulation treatment in 60 stages; 2) on a rigless intervention to spot a cap on a sand plug to abandon a set of perforations and help improve the injectivity profile in two wells; 3) during gas-tight re-cementing operations through casing perforations after poor primary cementing; and 4) during remediation of tight casing leaks in injection wells to meet mechanical integrity test regulations.

INTRODUCTION

Although epoxy resins have been used for zonal isolation and well remediation applications for decades (Gunningham et al. 1992), a recently developed epoxy resin system exhibits significant benefits over resins used in the past. This modern epoxy resin system exhibits exceptional resistance to contamination including oil-based and water-based fluids, favorable mechanical properties, a wide density range of 6.0 to 21.0 lbm/gal, adjustable placement time, a low yield point, and acid and abrasion resistance (Morris et al. 2014). It can be solids laden or used as a solids-free pure fluid and can be used during long-term applications up to 280°F. These properties, along with the availability of solids-free designs, make the resin an ideal candidate for a wide range of applications throughout the life of a well. In squeeze cementing operations, this epoxy resin system can be applied where conditions make particle-laden fluids undesirable and unable to penetrate areas previously inaccessible to conventional cement slurries, such as “tight” casing leaks, gravel packs, small fractures, channels, or microannuli. It also serves as a gas-tight barrier and is ideal for permanent plug and abandonment because the epoxy resin system can provide a high-performance seal (Urdaneta et al. 2014). A notable advantage of the epoxy resin system is that no special wellbore preparation is necessary. For example, water-wetting surfactants used ahead of cement in wells drilled with oil-based mud (OBM) are not necessary. Standard best practices should be followed for hole cleaning or for establishing injectivity before a squeeze. The resin is mixed and pumped on location using conventional cementing equipment. A cleaning solvent is usually used to clean equipment, lines, and tubing of any epoxy resin residue.

No special laboratory equipment is necessary to test the epoxy resin system and all the necessary equipment to do so can be found in a well-equipped oilwell cementing testing laboratory. The epoxy resin is mixed in the laboratory by adding the individual components together in a Waring® blender used for cement mixing. The blender is run at 2,000 RPM to achieve a homogenous mixture. Several common tests can be conducted including thickening time, rheological profile, and compressive strength. The thickening time of an epoxy resin is generally considered to be when the consistency reaches 100 Bc. However, if the slurry cup is immediately removed, the epoxy resin can be observed to pour from the slurry cup, and an inherent safety factor is included in placement time. Also, extended squeeze times past the thickening time are commonly observed. An ultrasonic cement analyzer (UCA) is valuable for determining the wait-on-resin (WOR) time, but the value for compressive strength is often lower than the value observed by measurement on a load frame. This is because the mathematical correlations used to calculate compressive strength are for cement instead of resin.

The epoxy-resin reaction is temperature dependent, and an accurate bottomhole static temperature (BHST) is the most critical design factor to help ensure adequate placement time, compressive-strength development, and drillout time considerations. At low temperatures (less than 150°F), the reaction rate of the epoxy resin and hardener proceeds slowly, and an accelerator is often used to increase the rate of strength development. At higher temperatures (greater than 150°F), the reaction is significantly driven by temperature, and no accelerator is necessary.

CASE STUDY 1: CASING LEAK SQUEEZE BEFORE STIMULATION OPERATIONS

Per regulatory requirements, an operator in the Midland Basin of West Texas conducted a mechanical integrity test (MIT) of 9,800 psi for 30 minutes in the 5.5 in 20 lbf-ft P-110 production casing of a recently drilled well before the 60-stage stimulation operation. After the MIT failed, a test packer was run in the hole to determine the location of the leak. As suspected, the leak was located at 5,971 ft, which was the depth of the multistage tool that was run as part of the production casing to perform primary cementing operations in two stages. An injection rate of 0.9 bbl/min at 4,400 psi was established at the leak. Various solutions to fix the leak were considered and discussed. A regular cement squeeze was discarded immediately. The small nature of the leak almost guaranteed that the relatively large cement particles in the cement slurry would provide little-to-no penetration for such a small leak, along with the improbability of a cement seal to hold for the duration of the entire stimulation treatment. Another option considered to address the leak was applying a casing patch over the multistage tool length. This possible solution had significant disadvantages. This included cost, the possibility the casing patch would not provide a complete seal, resulting in additional remedial operations, and most importantly, the reduction of the casing inner diameter (ID) that even the thinnest of casing patches would produce. This ID reduction could hinder the optimal completion of the well and necessitate the use of more costly slimhole fracturing plugs for “plug-and-perf” stimulation treatments. It could also necessitate the use of a smaller production packer, resulting in lower production rates. After further discussion, the epoxy resin system was selected as the best remediation option because of its many benefits, mainly the deep penetration, solids-free design, and ability to withstand acid degradation and proppant abrasion.

Laboratory Testing

Laboratory testing was conducted to select the optimal components ratio for the treatment. Using historical data for the area, the design temperature at the multistage tool was calculated to be 132°F—the most critical design factor.

A thickening time test was conducted on a high-pressure/high-temperature (HP/HT) consistometer at a 132°F BHST and a bottomhole pressure (BHP) of 4,100 psi to simulate downhole conditions and determine optimal placement time. To account for any adverse effects that might occur as a result of static shutdowns during pumping, a 1-hour shutdown was included in the thickening time. Table 1 displays the final epoxy resin design, and Figure 1 shows the thickening time graph. To determine the amount of WOR time to set before drillout, destructive compressive-strength tests were conducted. The resin system exhibited substantially high compressive strength and was able to sustain a high amount of strain without failure. After mixing, the resin was poured into three 2×2 ×2-in. cube molds and cured in a water bath at 132°F. After 24 hours, the resin cubes were removed from the molds, and a crush compressive-strength test was conducted on each cube. Figure 2 shows a stress vs. strain chart of this test. Because of safety considerations, the crush compressive-strength tests were stopped at 10,000 psi, without the resin failing. The mechanical compressive strain at that point was approximately 3.7%, illustrating the higher strain-to-failure values obtained with epoxy resin systems compared to Portland cement (Figure 3).

Unlike Portland cements slurries that exhibit Bingham-plastic rheological behavior, the resin system typically exhibits a Newtonian flow behavior, having little-to-no yield stress, thus allowing flow under extremely low forces (Jones et al. 2014). Rheological tests were conducted to help ensure that the system exhibited these properties, to squeeze it into the small leak in the multistage tool. The resin viscosity was such that measurements using a Fann® yield stress adapter (FYSA) with a Fann Model 35 viscometer provided a better rheological profile than the regular bob and sleeve configuration. The FYSA provides accurate rheological measurements of complex cement slurries and unconventional systems, such as epoxy resin (Gordon et al. 2007). The results are compiled on Table 2 and Figure 4.

Operation Execution

For logistical considerations and as a safety factor, a volume of 10 bbl of resin was selected. Because of the low injection rate of the leak, a bradenhead squeeze (also known as a "spot and squeeze") was selected as the remediation method. On a bradenhead squeeze, there is no cement retainer or packer, which helps reduce costs, drillout time, and the number of trips into the hole. The treatment is spotted across the leak; therefore, no wellbore fluids are squeezed ahead, and the squeeze pressure is applied to the entire column of fluid (Nelson et al. 2006; Rike et al. 1981). A cast-iron bridge plug (CIBP) was set approximately 49 ft below the leak at 6,020 ft MD. Although the epoxy resin is resistant to contamination, the well fluid was replaced with fresh water to help ensure the density hierarchy. Tubing was run in the hole and the CIBP was tagged. The maximum pressure for the squeeze operation was set at 5,000 psi. To mix the epoxy resin on site, 330-gal chemical totes were delivered to the location where a forklift was used to gravity feed the necessary amounts of the epoxy resin system components into a batch mixer blender. During this stage, the epoxy resin was mixed by agitating the paddles of the batch mixer blender at medium speed until a clear and homogenous mixture was achieved. The accelerator component is available in 5-gal pails, and it was added to the epoxy resin system last. At this point, the final epoxy resin system was mixed for 15 minutes. Table 10 and Figure 5 summarize the treatment schedule. The 10 bbl of resin were boosted to a regular cementing pump trailer and spotted downhole across the leak using the balanced plug method. After placement, tubing was pulled slowly out of the balanced plug at a rate of 90 seconds per stand to help ensure the balanced plug was not disturbed. Tubing was pulled 1,000 ft above the calculated epoxy resin top to approximately 5,100 ft MD. Subsequently, the tubing was reversed out with fresh water to clean any epoxy resin residue. The blind rams of the blowout preventer (BOP) were closed and the bradenhead squeeze operation began (Figure 6). A rapid increase in pressure indicated the casing was full and pressure was being applied to the entire column of fluid, thus pushing the resin treatment into the leak. Because of the solids-free design of the epoxy resin and different chemical composition, a squeeze pressure typical of a cement remedial operation could not be achieved. In this scenario, there was a risk of overdisplacing the resin treatment and thus accurate displacement volumes were crucial. A total of 6 bbl of resin were counted as being injected into the leak with a maximum pressure of 3,500 psi. Subsequently, the squeeze operation was shut down, and the well was shut-in after pressure decreased to almost 2,900 psi.

Resin Drillout and MIT

The well was shut-in with 2,900 psi for 24 hours to allow sufficient time for the resin to cure. Before drilling out the epoxy resin, a pressure test of 5,000 psi was conducted to help ensure the leak was isolated. A 4 5/8-in. junk mill (Figure 7) was run on 2 7/8-in. 6.5 lbf-ft L-80 tubing. This size mill was 99.4% the drift of the 5.5in. 20 lbf-ft P-110 casing. The remaining epoxy resin inside the casing was drilled with 500 to 1,000-lb_f weight on bit at 90 RPM to the top of the CIBP in nearly 10 hours. Subsequently, the well was pressurized to 9,800 psi for 30 minutes with no leakoff, thus successfully passing the MIT.

Stimulation Treatment

After passing the regulatory pressure test for the casing, the well was successfully stimulated in 60 stages, with no signs of the leak. Table 3 summarizes the stimulation operations.

CASE STUDY 2: RIGLESS ISOLATION OF LOWER SET OF PERFORATIONS

To improve the sweep efficiency and oil recovery in a CO_2/water alternating gas (WAG) injection flood, an operator sought to improve the vertical injection profile in two injection wells. A wireline injection profile survey indicated that 65 to 70% of the injection fluids were being lost to the lower set of perforations in both injection wells. To maintain low remediation costs, the operator sought to isolate the lower set of perforations in both wells by means of a rigless intervention through the production tubing. The devised solution consisted of pumping a sand plug down the production tubing to cover the perforations, followed by an epoxy resin cap run on a wireline dump bailer to provide a seal on top of the sand plugs.

Operation Planning and Laboratory Testing

Because both injection wells were in close proximity in the same field, it was decided to perform the remediation in both wells consecutively. Table 4 shows the wellbore configurations and sand plug length designs. The smallest ID in both wellbores was 1.875 in.; therefore, a 1.5-in. dump bailer size was selected to spot the epoxy resin caps. To help ensure proper sand displacement to the bottom of the wells, a crosslinked gel was selected as the carrier fluid. Table 5 shows the crosslinked gel design. The sand selected for the plugs was 20/40-mesh premium brown because of availability and logistics considerations. Laboratory testing was conducted to determine the optimal breaker concentration to help ensure the gel broke down in the allotted time and sand settled at the bottom of the wells. To help ensure further compaction and a better transition from sand to epoxy resin at the top of the sand plug, finer 200-mesh sand was used as a weighting agent for the epoxy resin. A thickening time test for placement time was conducted, which included a mixing period and a static period, plus a safety factor in case the dump bailer charge failed and an additional trip was necessary. Table 6 and Figure 8 show the final epoxy resin design and thickening time test graph, respectively.

Operation Execution

The operation for both wells was broken down in two days. On Day 1 the sand plugs were pumped to the planned heights and the wells left on injection overnight to compact the sand. On Day 2 additional sand would be pumped, if necessary to achieve the necessary height, along with the dump-bailed epoxy resin cap. Because of the relatively small amount of materials necessary, a single-pump acid pumping trailer was used to pump the sand plugs. This trailer unit has a CLAM™ (constant level additive mixer) tub that enables the addition of additives on the fly. Figures 9 and 10 show the trailer unit and the CLAM. The gel was prehydrated in the pumping trailer tanks, followed by the addition of breaker, 20/40-mesh sand, and crosslinker through the mixer tub before going downhole. After pumping the planned amount of sand in Well 1, the pumping trailer unit was moved to the Well 2, while waiting on the gel to break and the sand to settle on the Well 1. A wireline unit would then run in the Well 1 to tag the sand top. After achieving the desired sand coverage in both wells, the wells were put on injection until the next morning to compact the sand and provide a stable base for the resin cap. On the second day of operations, a wireline tag run was conducted on both wells to measure the height difference after the expected compaction. Both wells needed more sand. Therefore, additional sand was pumped and dump bailed to achieve the final coverage. A total of 2,100 lbm of sand were pumped in Well 1 and 2,250 lbm in Well 2. After achieving the final top of sand, the epoxy resin was mixed in a 5-gal bucket using an electric power drill with a paddle adapter (Figure 11) and then loaded into the wireline dump bailer (Figure 12). The dump bailer was then run in the wells to place the epoxy resin caps.

Results

Samples of the sand and epoxy resin from location were collected into jars to monitor the epoxy resin setup. Figure 13 illustrates one of these samples with water added for effect, showing an impermeable seal between the water and the sand. The epoxy resin provided an impermeable seal on top of the sand plugs in both wells and isolated the bottom set of perforations, thus improving the injectivity profiles as indicated by the pre- and post-job injection rates in Figure 14. The data shows a decrease in injectivity on both wells proportional to the amount of fluid that the newly covered thief zone took historically.

CASE STUDY 3: GAS TIGHT ANNULAR RE-CEMENTATION

To abandon a well in Gaines County, Texas, an operator had to shut off 300 psi of bradenhead pressure in the production casing annular. Because of inadequate primary cementing coverage on the 5.5-in. 17 lbf-ft production casing, gas was migrating from the Yates formation. The estimated top of the Yates formation in that area is around 2,930 ft MD. To shut off the gas migration, a novel gas-tight abandonment treatment was developed. This treatment consisted of shooting perforations above the production casing top of cement (TOC) and pumping 3 bbl of epoxy resin and neat Class C cement into the annulus, followed by just neat Class C cement inside of the casing. Figure 15 shows a wellbore diagram.

Laboratory Testing and Operation Execution

A thickening time test for the epoxy resin was conducted at 103°F and 2,400 psi on a HP/HT consistometer to simulate bottomhole conditions. Table 7 and Figure 16 show the final epoxy resin design and thickening time graph, respectively. Because the epoxy resin was going to be pumped adjacent to neat cement, several tests were conducted to help ensure the compatibility and stability of an 80% neat cement and 20% epoxy resin mixture. A thickening time test of this mixture (Figure 17) resulted in no compatibility issues or erratic behavior and pumped off at 3 hours 26 minutes. This was slightly slower than the neat epoxy resin pump time of 4 hours 9 minutes but well within design parameters. A free fluid/stability test (Figure 18) was conducted and showed no separation, streaks, or discoloration that would indicate incompatibility between cement and the epoxy resin. The rheological profile of the Class C cement and epoxy resin mixture was also within the expected viscosity (Table 8).

After perforating the production casing, a treatment packer was run in the hole with tail tubing below it. Circulation was established at 1 bbl/min and 1,026-psi pump pressure. The epoxy resin components were mixed in a 330-gal tote tank in the order indicated in Table 7, with a gasoline-operated centrifugal pump and a pneumatic paddle mixer. The tote tank was then lifted with a forklift and connected to the pump suction side of the cementing trailer unit. The 3 bbl of epoxy resin were pumped followed by 43 sks of neat Class C cement. Displacement was calculated to leave enough cement inside the casing for the necessary abandonment plug at that depth. After shutting the well for 48 hours to wait for the epoxy resin to fully cure, the production casing annular was bled off, after which there was no gas migration or pressure buildup. The operator set the remaining cement plugs, and the well was abandoned successfully.

CASE STUDY 4: SEAL CASING LEAK ON INJECTION WELL

The operator of a CO_2 flood in West Texas had a scheduled MIT in one of its injector wells. Regulations in Texas define a successful MIT when the test pressure stabilizes for 30 minutes at a pressure within 10% of the starting pressure, which in this case was 500 psi. The test resulted in a very low loss of pressure of 50 psi in 48 minutes. This indicated the pressure never stabilized, therefore failing the test. The operator identified a leak in the 7-in. 26 lbf-ft N-80 casing between 10,174 and 10,206 ft MD. Because of well longevity, a combination, or wear, tear, and corrosion were suspected as the leak causes. The operator had to mend the casing leak permanently in a timely manner, without costly multiple treatments that traditional remediation methods for “tight” casing leaks usually use. To accomplish this, the epoxy resin system was selected as the remediation method because of its solids-free design, ability to penetrate tight leaks at a very low shear rate, and high differential pressure resistance.

Laboratory Testing

A thickening time test was conducted at 157°F and 6,900 psi in a HP/HT consistometer to simulate bottomhole conditions. This test included sufficient time to mix and pump the epoxy resin, reverse circulate the tubing, and a safety factor. Figure 19 shows the test results, and Table 9 shows the final epoxy resin design and volume. The epoxy resin design called for no accelerator at this temperature, resulting in a working placement time of 5.5 hours.

Operation Execution

Because no injection rate was established at the leak, only a loss of pressure over time, the use of a squeeze packer was discarded and a bradenhead squeeze was selected as the remediation method. A CIBP was set at 10,225 ft MD, approximately 49 ft below the casing leak depth. The epoxy resin was mixed in a batch mixer blender as described in Case Study 1. Tubing was run in the hole and the epoxy resin was placed across the leak, using the balance plug method. After placement, tubing was pulled to 8,867 ft MD, which was approximately 1,000 ft on top of the calculated epoxy resin top. The tubing was reversed out with fresh water to clean any epoxy resin residue. The workover rig reverse pump unit was then used to pressurize the well to 500 psi several times, before leaving the well shut-in with pressure.

Resin Drillout and MIT

The well was shut-in for 48 hours to allow sufficient time for the resin to cure. A 5 3/4-in. five-bladed mill was run on 2 7/8-in. 6.5 lbf-ft L-80 tubing. The top of the epoxy resin was tagged at 10,070 ft MD. The remaining epoxy resin was drilled to the top of the CIBP at 10,255 ft MD, at which point a MIT was conducted, holding 500 psi for 30 minutes, therefore passing the MIT. The operator drilled the CIBP, ran the disposal packer and tubing, performed the official MIT in front of the regulatory body 5 days later, and was able to put the well back into injection in a timely matter.

CONCLUSIONS

This paper presents the wide range of epoxy resin system applications through the life of a well. After placement, the epoxy resin system crosslinks into a chemically stable elastic, high-strength impermeable barrier capable of withstanding high-pressure differentials. The epoxy resin system allows for wellbore integrity restoration without the use of costly and ineffective traditional remediation methods. Through effective issue-identification techniques, solution development, and operational execution, the use of epoxide resin technology is a valuable tool for both service companies and operators during wellbore remediation efforts.

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Table 1 – Case Study 1: Epoxy Resin Design

Component	SG	Density (lbm/gal)	Weight (lbf)	%BWOR1	Volume (gal)
Resin 1	1.14	9.51	3042	100.0%	320
Hardener	1.02	8.51	821	27.0%	97
Accelerator	0.97	8.10	30	1.0%	4
				Total Volume (gal) =	420
				Total Volume (bbl) =	10
				Density (lb/gal) =	9.3

BWOBR1% = By Weight of Base Resin 1 percentage.

Table 2 – Case Study 1: Epoxy Resin Rheological Profile

Shear Rate (1/sec)	70°F	132°F
	Shear Stress (Pa)	Shear Stress (Pa)
166.8	104.489	38.291
83.4	52.569	12.331
55.6	34.397	7.139
27.8	17.523	3.894
16.68	10.384	2.596
8.34	5.192	1.947
1.668	1.298	0.649
0.834	0.649	0.649

Table 3 – Case Study 1: Stimulation Treatment Rates and Pressures

Stage No.	Average Rate (bbl/min)	Maximum Rate	Average Pressure (psi)	Maximum Pressure (psi)	Proppant (lbm)
1	80.1	86.2	8,311	8,865	293,895
2	90.1	90.6	7,130	7,692	293,586
3	89.9	90.3	6,939	7,542	299,920
4	90.0	92.0	7,064	8,403	289,802
5	91.2	92.4	6,603	8,926	316,442
6	90.2	90.8	6,609	7,648	313,545
7	89.7	90.0	6,637	7,870	316,788
8	89.6	90.4	6,676	8,272	313,550
9	89.8	91.2	7,093	8,395	314,815
10	90.1	90.3	6,816	8,362	312,383
11	99.0	100.5	7,189	8,937	311,860
12	99.6	100.5	6,981	8,606	311,975
13	100.0	101.0	7,032	7,565	326,898
14	99.2	101.0	6,820	7,292	311,700
15	98.4	100.7	6,890	8,608	298,350
16	99.5	100.3	6,823	10,049	335,360
17	100.0	101.0	6,803	7,312	320,266
18	99.8	100.7	6,832	8,542	312,110
19	100.6	101.3	6,274	7,650	320,110
20	99.8	100.1	6,198	8,405	311,720
21	98.0	101.0	6,520	7,554	418,053
22	99.8	100.8	6,613	8,395	310,930
23	99.7	101.4	6,629	8,705	311,540
24	97.5	101.1	6,622	8,908	311,510
25	94.5	101.0	7,665	8,713	311,730
26	99.0	101.0	7,200	7,309	314,030
27	99.0	100.4	7,371	8,848	315,350
28	100.0	100.7	7,090	8,472	312,580
29	96.0	101.0	7,700	8,824	316,090
30	79.3	101.0	8,100	9,150	311,950
31	86.3	101.0	6,943	9,690	311,780
32	100.6	100.8	6,497	7,248	303,555
33	100.2	100.5	6,527	7,555	303,445
34	99.9	100.3	6,950	7,663	313,005
35	90.0	101.0	6,440	8,022	438,942
36	88.6	101.0	6,580	7,820	450,431
37	90.9	100.9	6,743	7,739	451,815
38	95.0	100.3	7,231	8,462	451,752
39	100.6	100.8	6,075	6,479	284,483
40	101.0	101.0	6,510	8,678	276,333
41	100.0	101.0	6,270	6,692	290,563

Table 3 (continued) – Case Study 1: Stimulation Treatment Rates and Pressures

Stage No.	Average Rate (bbl/min)	Maximum Rate	Average Pressure (psi)	Maximum Pressure (psi)	Proppant (lbm)
42	100.0	101.0	6,283	6,804	290,563
43	100.7	101.0	6,326	8,762	294,938
44	100.9	101.1	6,215	7,666	297,953
45	100.7	101.0	5,987	7,827	288,003
46	100.8	101.2	5,851	7,439	288,003
47	90.5	101.3	5,807	6,889	287,853
48	100.7	101.0	5,838	6,751	287,753
49	95.0	101.0	5,862	6,832	293,613
50	101.0	101.4	5,898	6,613	293,613
51	100.0	101.0	6,177	7,978	293,402
52	100.0	102.0	5,643	7,656	288,763
53	100.0	100.8	5,864	7,826	295,716
54	100.0	101.2	6,136	7,683	293,618
55	100.0	101.7	6,341	7,802	294,435
56	100.0	101.1	6,047	7,825	294,732
57	100.0	101.4	6,213	8,513	294,564
58	100.0	101.5	6,332	8,209	295,562
59	100.0	100.4	6,336	7,681	289,270
60	100.0	100.5	6,569	7,368	282,470
Average	96.5	-	6,629	-	314,663
Maximum	-	102.0	-	10,049.0	-
Total	-	-	-	-	18,879,766

Table 4 – Case Study 2: Wellbore Configurations and Sand Plug Designs

	Well 1	Well 2
WELLBORE INFO		
Current PBTD	4,610	4,741
Tagged TD, ft	4,597	4,626
Casing Grade	K-55	K-55
Casing OD, in.	7	5.5
Casing ID, in.	6.366	5.012
Tubing Length, ft	4,244	4,289
Tubing OD, in.	2.875	2.875
Tubing ID, in.	2.441	2.441
Tubing Drift, in.	Duoline 1.945	Duoline 1.945
Minimum ID, in.	1.875	1.875
Casing Capacity, bbl/ft	0.0394	0.0244
Tubing Capacity, bbl/ft	0.0058	0.0058
Tubing Volume, bbl	36	25
DESIGN		
Sand Plug Target PBTD, ft	4,540	4,555
Maximum Range, ft	4,533	4,528
Minimum Range, ft	4,549	4,580
Sand Plug Length (PBTD), ft	70	186
Sand Plug Length (Tagged), ft	57	71
Plug Volume (PBTD), bbl	2.756	4.539
Plug Volume (Tagged), bbl	2.244	1.733
Sand Needed PBTD, lbm	1,653	2,723
Sand Needed (Tagged) lbm	1,346	1,040
Gel Slurry (PBTD), bbl	7.9	13
Gel Slurry (Tagged), bbl	6.4	5
Gel Slurry (PBTD), gal	331	545
Gel Slurry (Tagged), gal	269	208
Fresh Water Flush, bbl	27	31
Maximum Injection Rate, B/D at 1,200 psi	2,000	2,000
Maximum Injection Rate, bbl/min at 1,200 psi	1.4	1.4
2-ft Resin Cap Volume, gal	3.31	2.05

Table 5 – Case Study 2: Crosslinked Gel Design

Component	Concentration
Low Residue Guar Gum Gel	40.0 lbm/Mgal
Borate Crosslinker	1.0 gal/Mgal
Enzyme Breaker	0.5 lbm/Mgal

Table 6 – Case Study 2: Epoxy Resin Design

Component	SG	Density (lbm/gal)	Weight (lbf)	%BWOBR1	Volume (gal)
Base Resin 1	1.14	9.51	17	100.0%	1.79
200-mesh Sand	2.65	22.12	14.3	83.2%	0.65
Hardener	1.02	8.51	5	27.0%	0.54
Accelerator	0.97	8.10	30	1.0%	0.02
				Total Volume (gal) =	3.0
				System Density (lbm/gal) =	12.0

Table 7 – Case Study 3: Epoxy Resin Design

Component	SG	Density (lbm/gal)	Weight (lbf)	%BWOBR1	Volume (gal)
Base Resin 1	1.14	9.51	656	100.0%	69
Base Resin 2	1.09	9.10	218	33.3%	24
Hardener	1.02	8.51	254	38.7%	30
Accelerator	0.97	8.10	26	4.0%	3
				Total Volume (gal) =	126
				Total Volume (bbl) =	3
				System Density (lbm/gal) =	9.2

Table 8 – Case Study 3: Class C Cement and Epoxy Resin Mixture Rheological Profile

Shear Rate (1/sec)	70°F	103°F
	Shear Stress (Pa)	Shear Stress (Pa)
175.8	37.6	30.7
87.9	18.1	26.5
58.6	15.3	22.3
29.3	13.2	19.5
17.6	11.2	17.4
8.8	9.8	9.1
1.8	8.4	7.7
0.9	8.4	7.7

Table 9 – Case Study 4: Epoxy Resin Design

Component	SG	Density (lbm/gal)	Weight (lbf)	%BWOBR1	Volume (gal)
Base Resin 1	1.14	9.51	3683	100.0	387
Hardener	1.02	8.51	995	27.0	117
				Total Volume (gal) =	504
				Total Volume (bbl) =	12
				System Density (lbm/gal) =	9.3

Table 10 – Case Study 1: Treatment Log for Figures 5 and 6

Event No.	Description	Time
1	Begin operation	01:05:00
2	Test lines	01:08:33
3	Establish injection rate	01:23:54
4	Mix epoxy resin	01:42:58
5	Pump epoxy resin	03:17:50
6	Pump freshwater displacement	03:24:34
7	Clean lines/pick up tubing	03:38:17
8	Reverse circulate tubing	04:35:25
9	Close BOP/squeeze 6 bbl	04:51:21
10	Shut-in well/end operation	05:18:11

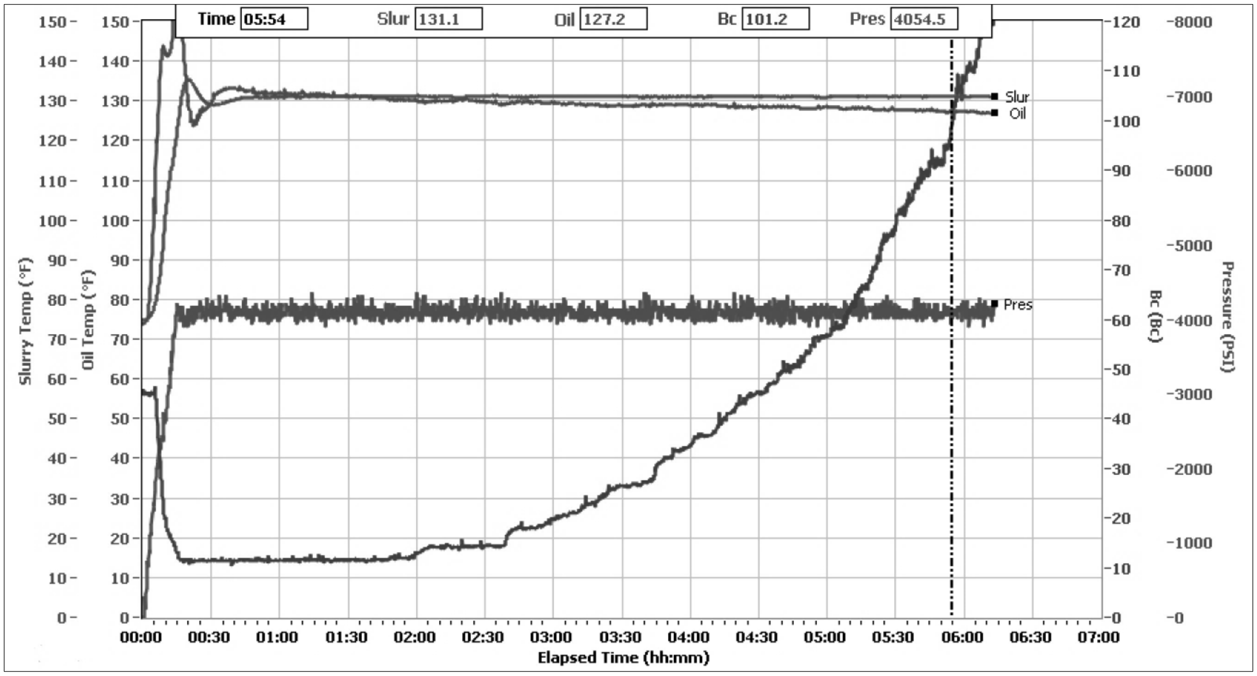

Figure 1 – Case Study 1: Epoxy resin thickening time test.

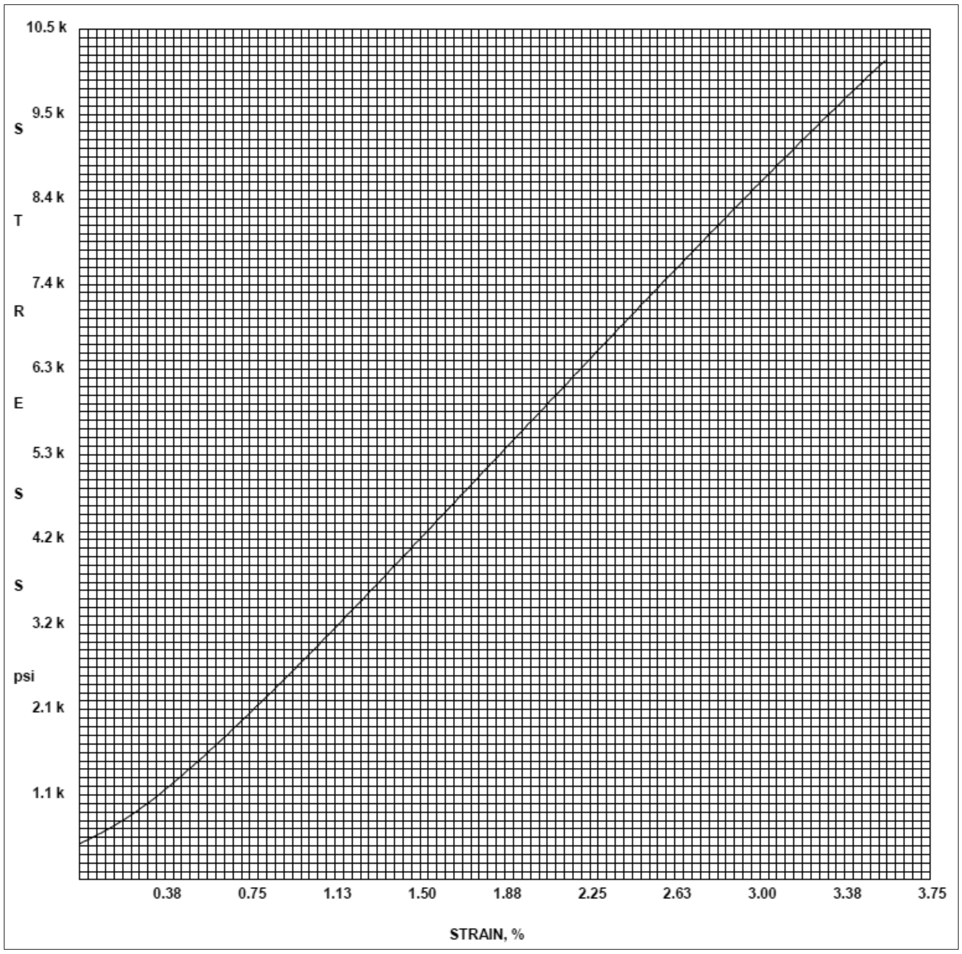

Figure 2 – Case Study 1: Epoxy resin unconfined compressive stress vs. strain chart.

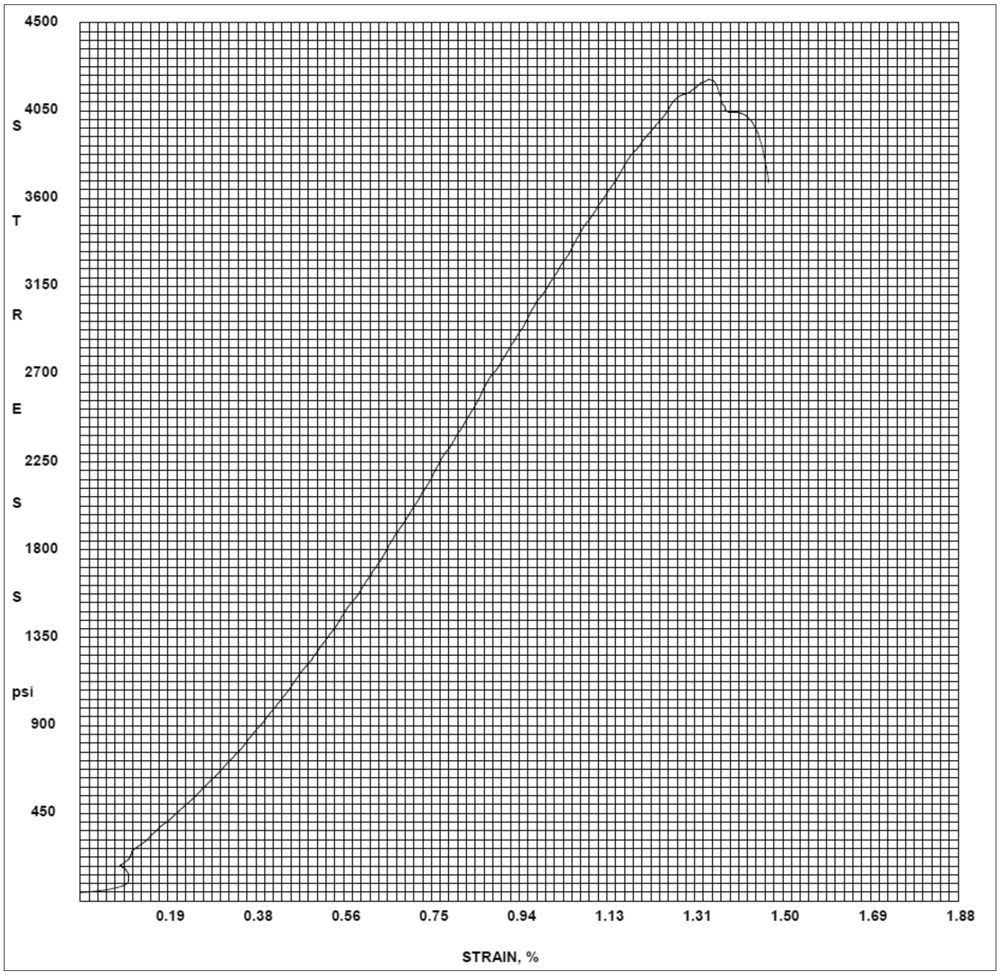

Figure 3 – Case Study 1: Class H cement unconfined compressive stress vs. strain chart.

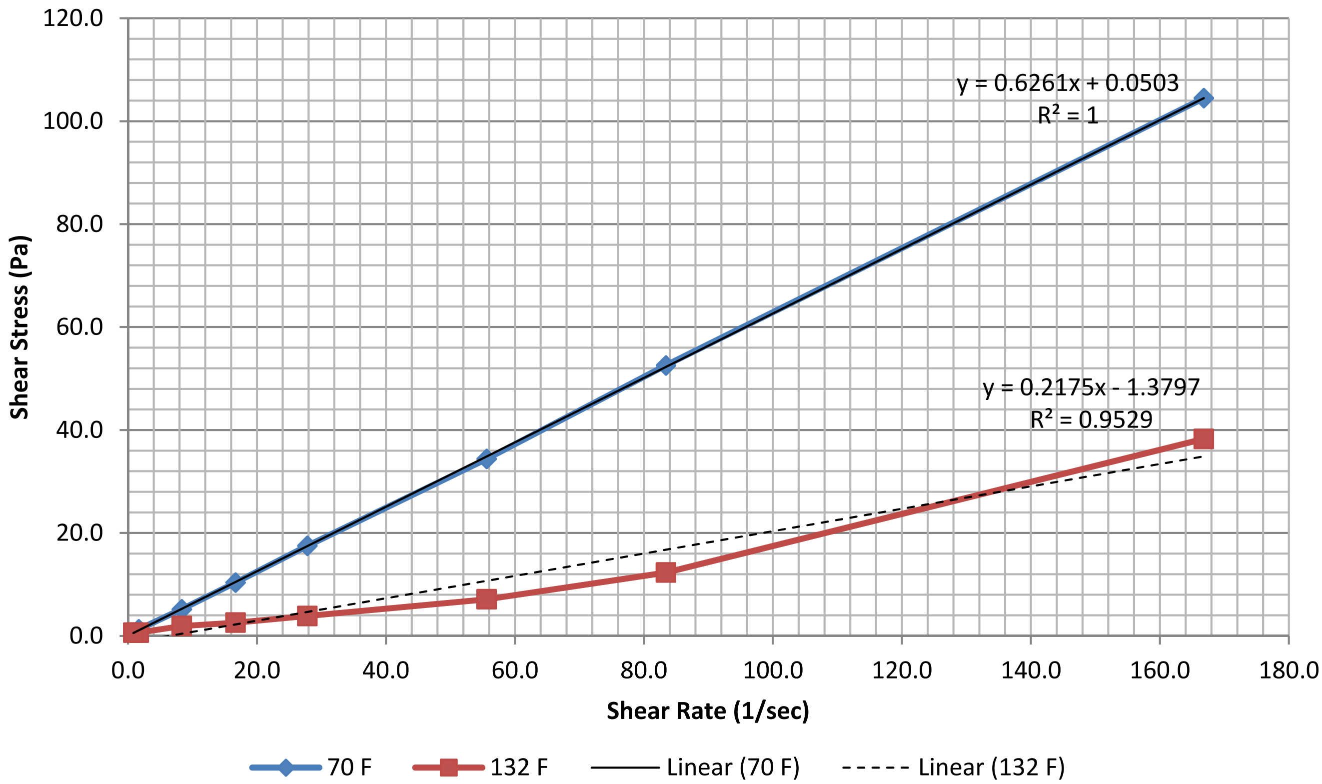

Figure 4 – Case Study 1: Epoxy resin shear stress vs. shear rate chart.

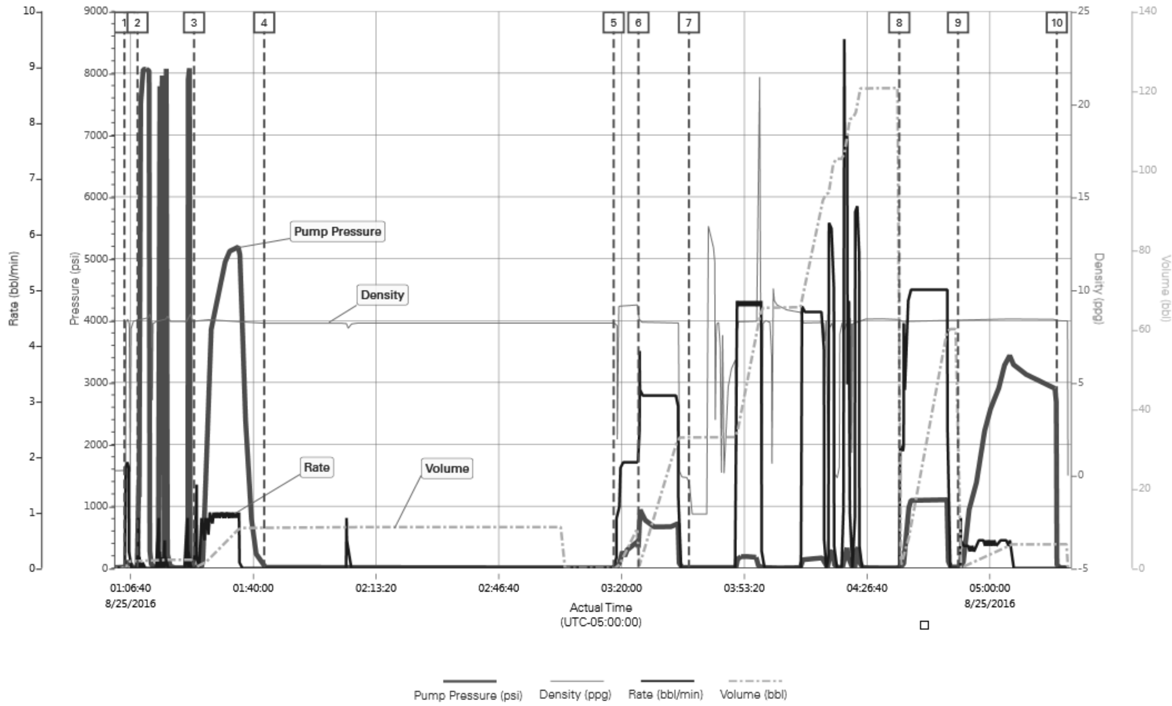

Figure 5 – Case Study 1: Epoxy resin squeeze operation summary (See Table 10).

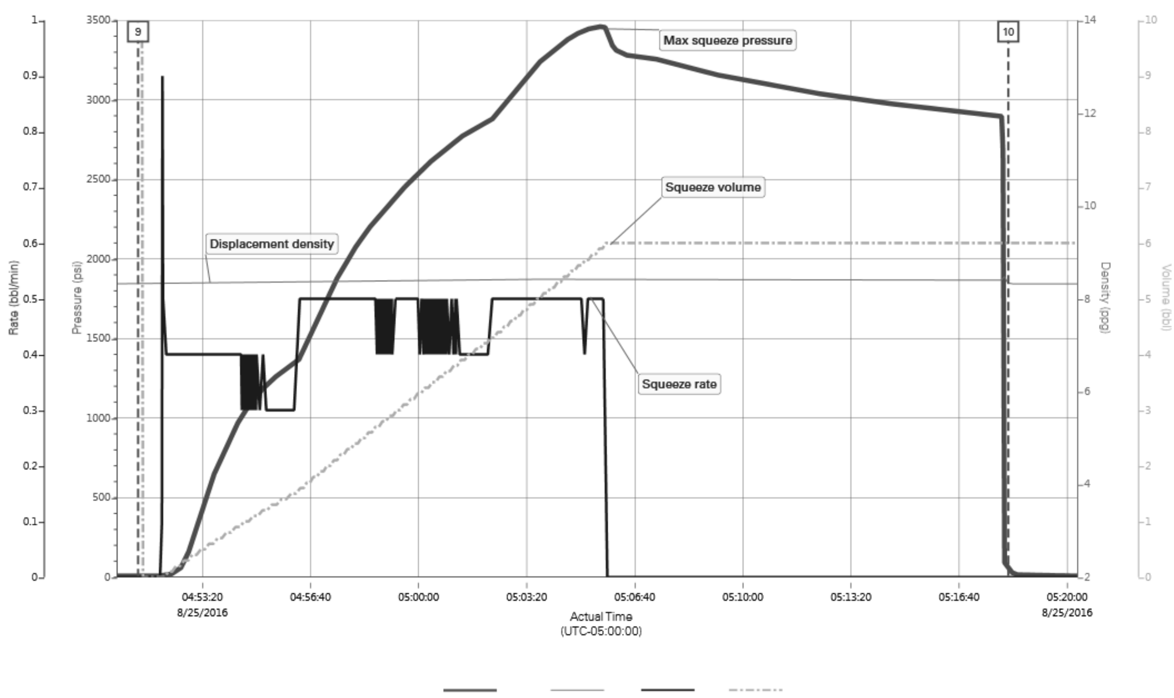

Figure 6 – Case Study 1: Epoxy resin bradenhead squeeze pressure up close up (See Table 10).

Figure 7 – Case Study 1: 4 5/8–in. junk mill used for epoxy resin drillout.

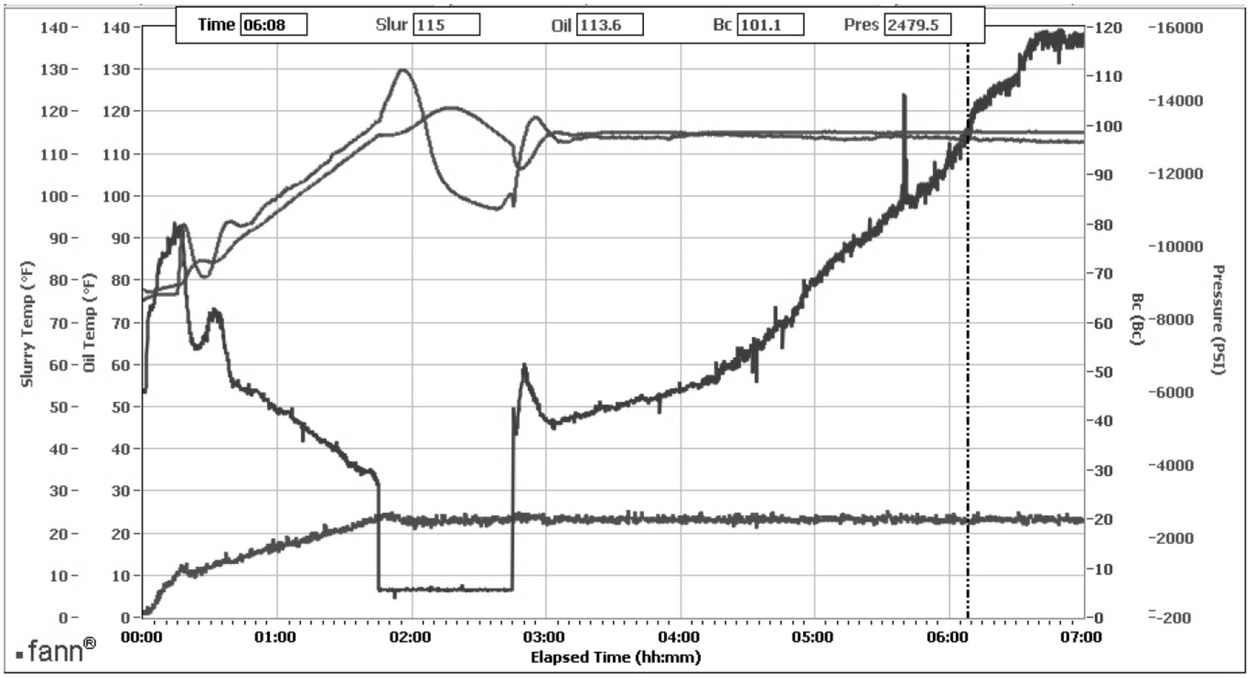

Figure 8 – Case Study 2: Epoxy resin thickening time test graph.

Figure 9 – Case Study 2: Single-pump acid pumping trailer.

Figure 10 – Case Study 2: CLAM tub on passenger side of single-pump acid pumping trailer.


Figure 11 – Case Study 2: Low volume epoxy resin mixing in 5-gal bucket.

Figure 12 – Case Study 2: Loading of epoxy resin into 1.5-in. dump bailer.

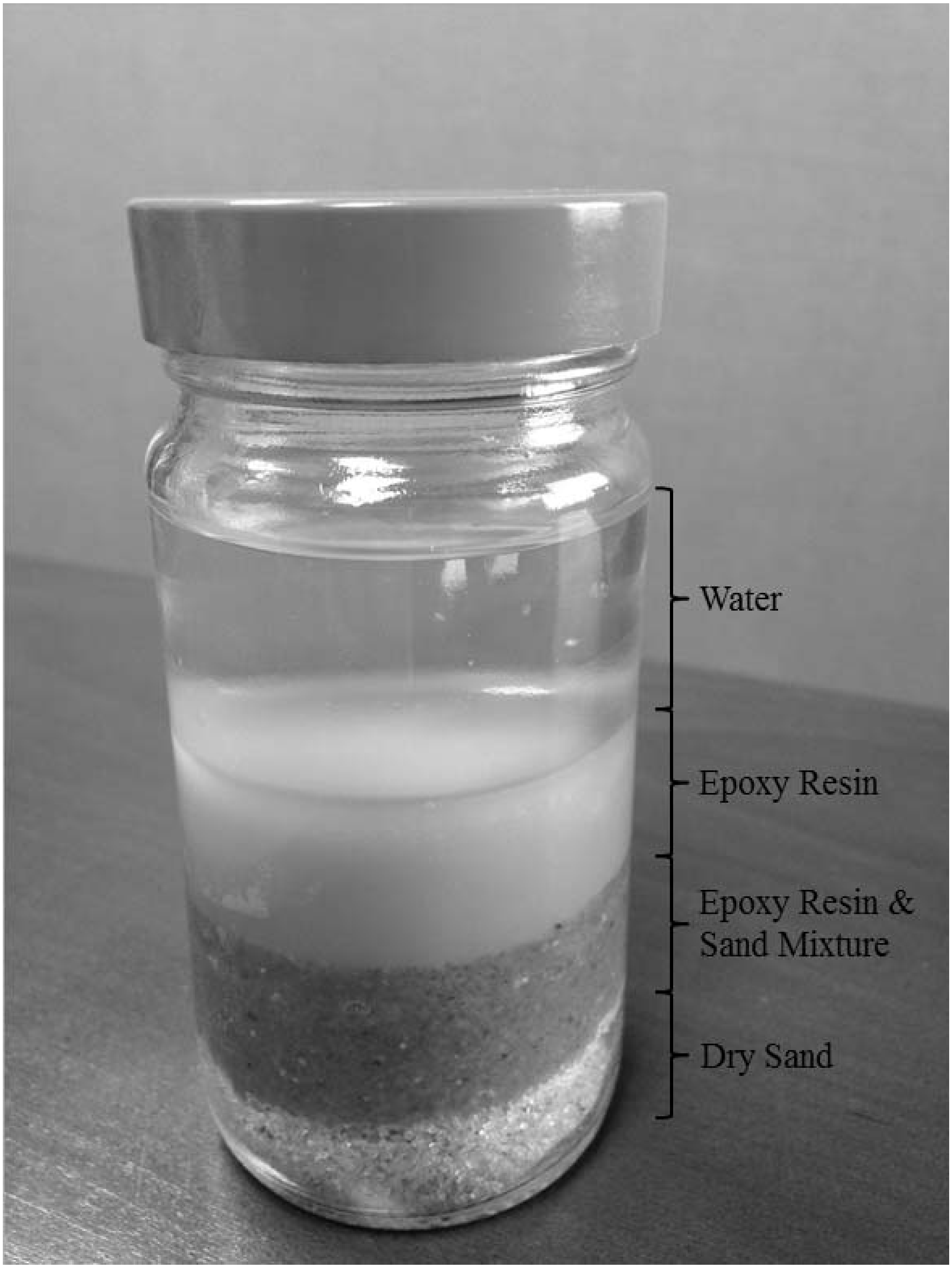

Figure 13 – Case Study 2: Location sample of set epoxy resin and 20/40-mesh sand, with water added for effect.

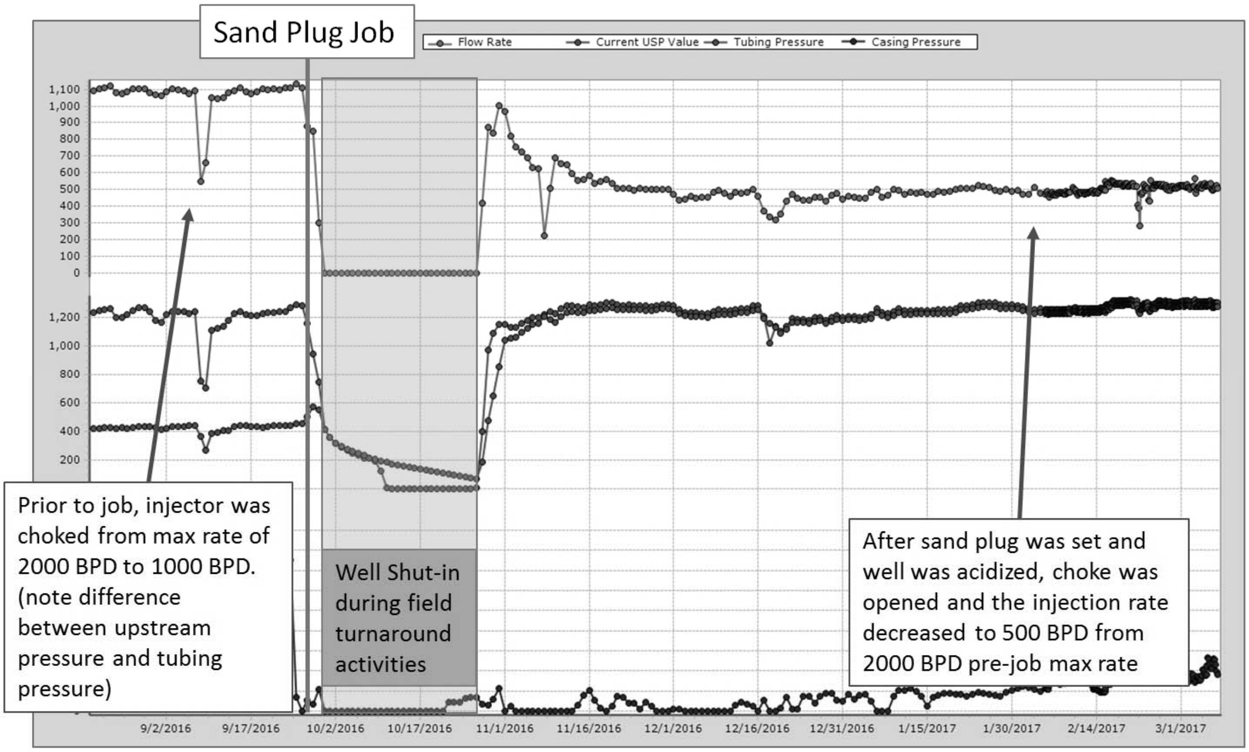

Figure 14 – Case Study 2: Pre- and post-treatment injection rate and pressure data for Well 1.

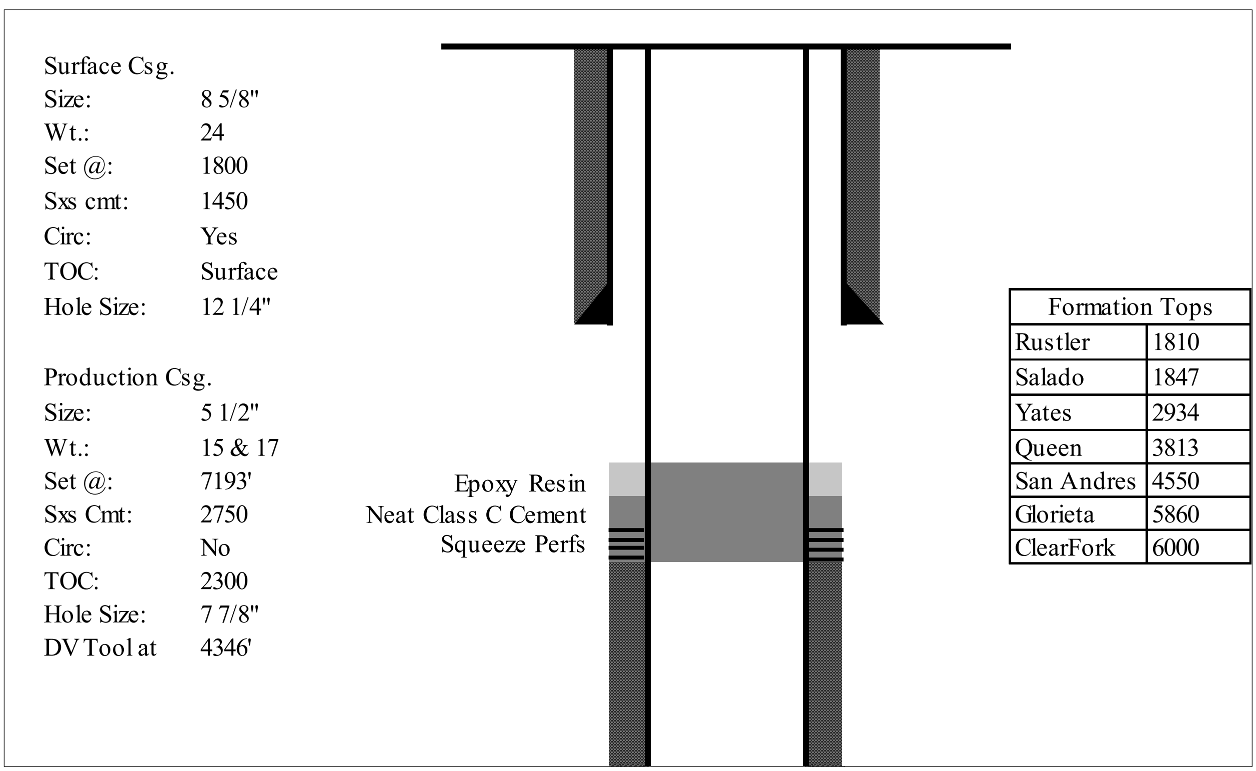

Figure 15 – Case Study 3: Gas-tight annular plug and wellbore diagram.

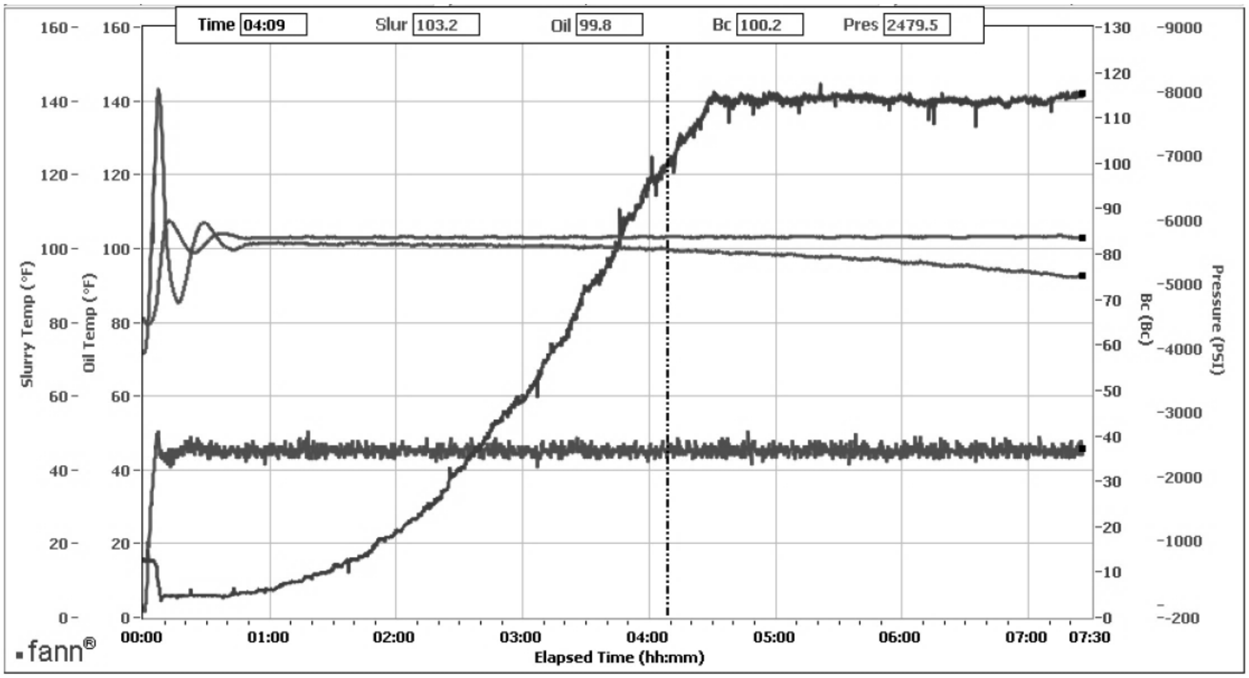

Figure 16 – Case Study 3: Epoxy resin thickening time test graph.

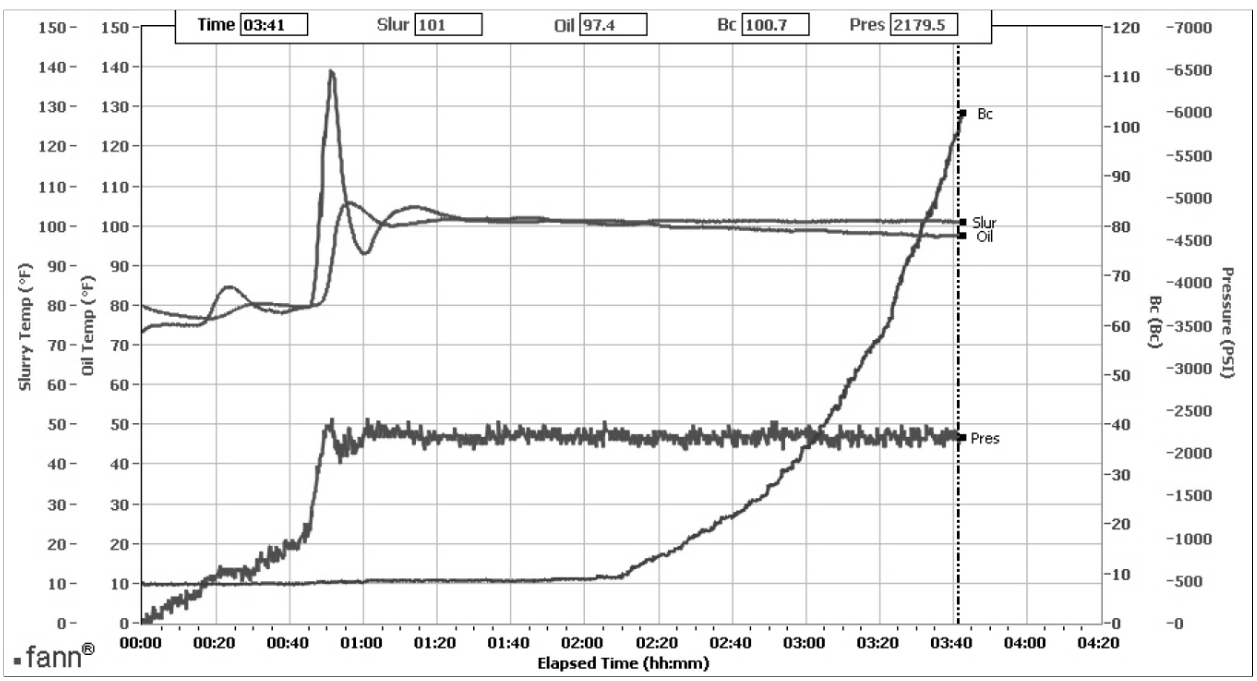

Figure 17 – Case Study 3: Class C cement and epoxy resin mixture thickening time test graph.

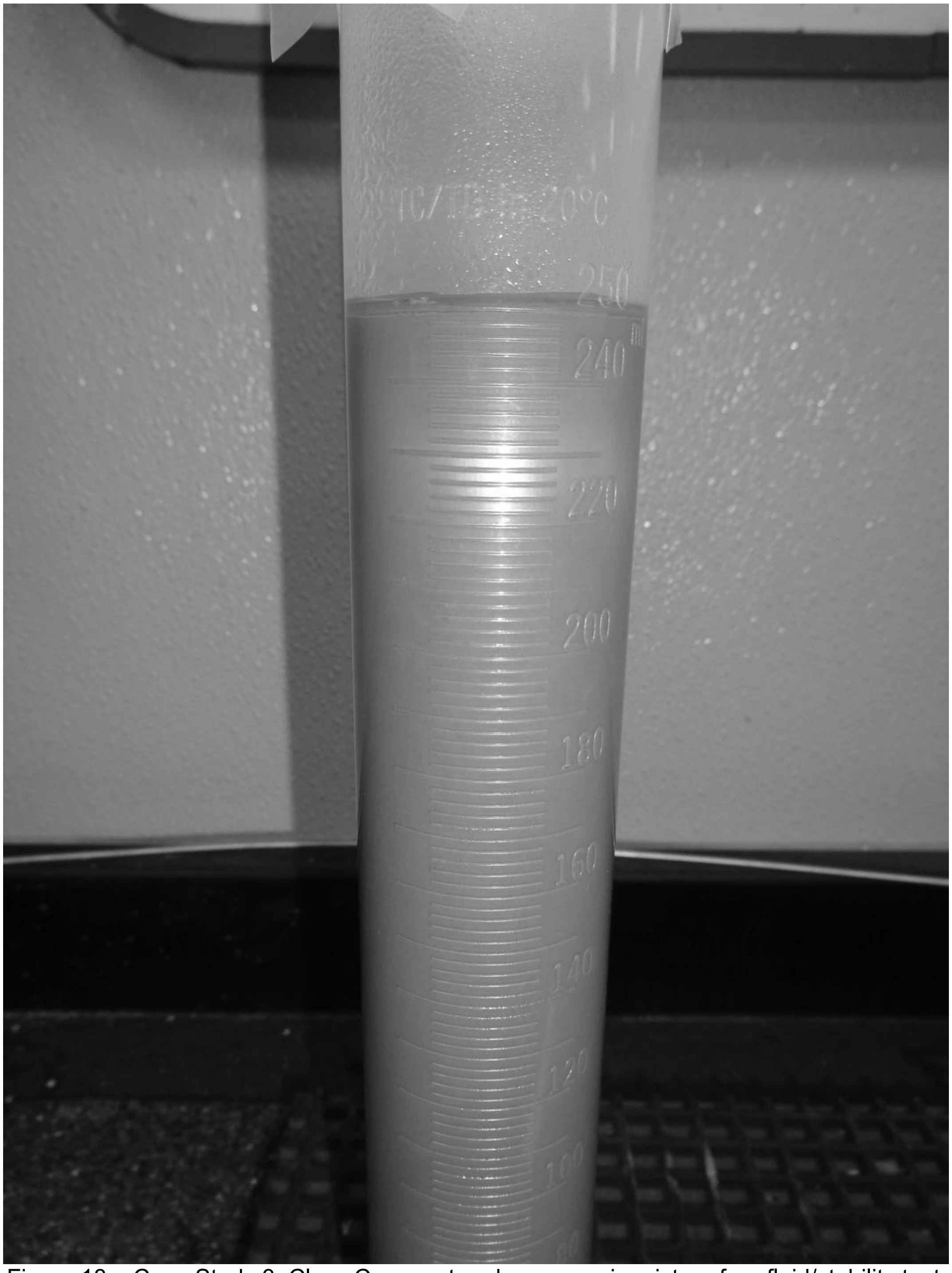

Figure 18 – Case Study 3: Class C cement and epoxy resin mixture free fluid/stability test.

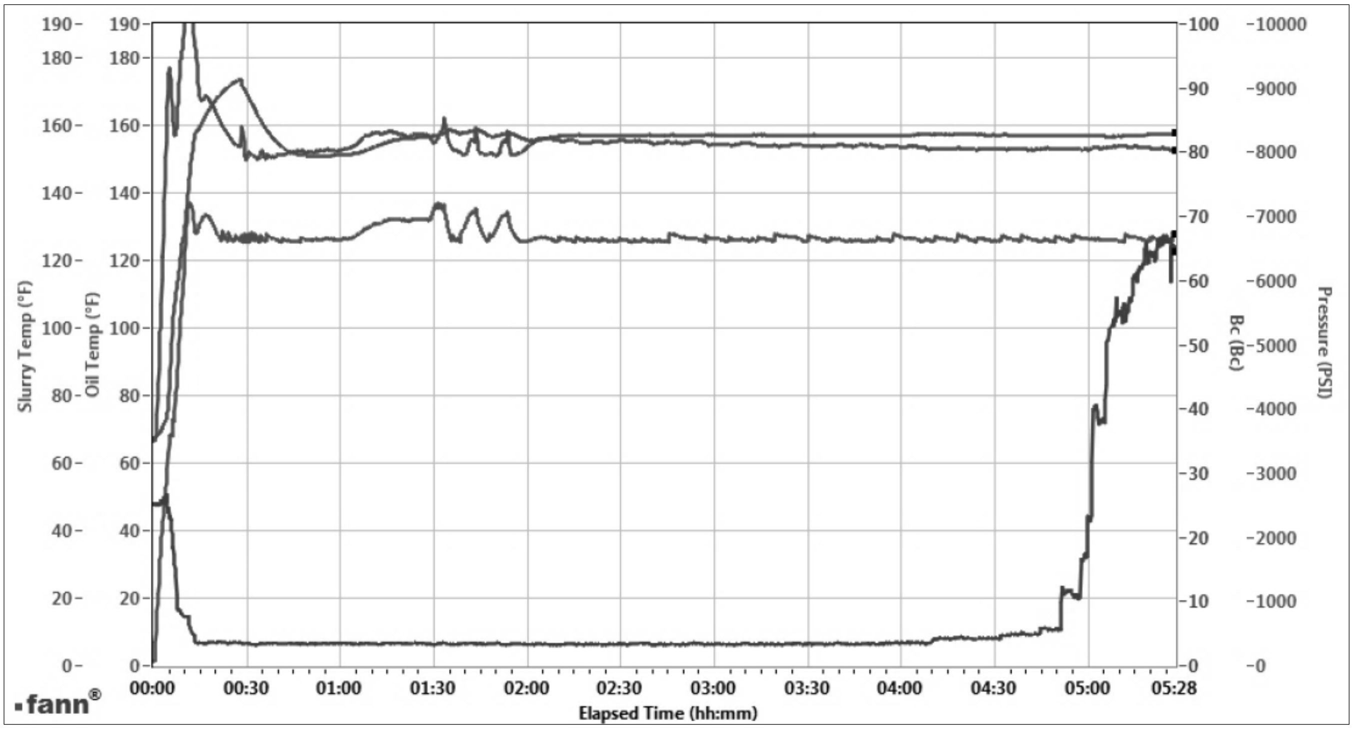

Figure 19 – Case Study 4: Epoxy resin thickening time test graph.