ELIMINATING CASING PATCHES AND RESTORING WELLBORE INTEGRITY - A SOLIDS FREE RESIN SYSTEM CAPABLE OF WITHSTANDING STIMULATION TREATMENTS

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ABSTRACT

The development of horizontal drilling combined with hydraulic fracturing has allowed operators to develop unconventional shale plays once considered uneconomical. As operators move toward longer horizontal and multilateral sections in these plays, the complexity with respect to well stimulation and completion systems increases. Before a well is stimulated or completed, critical problems can emerge, such as casing leaks. Depending on the well configuration, traditional remediation methods might be unable to withstand stimulation treatments, are difficult to apply and/or create a restriction in the casing inside diameter. This paper discusses how an acid and abrasion resistant resin system was applied to remediate a tight leak in the multi-stage cementing tool of a 5.5 in. production casing and enabled the operator to pass a pressure test and carry out the planned stimulation of the well in twenty-five stages, without any signs of a leak.

INTRODUCTION

Casing leaks can be a recurring problem in both old and new wellbores. These can stem from corrosion, casing wear, splits, thread failure, casing defects and casing equipment failure. Often, a continuous injection rate cannot be established in the presence of some leaks. Instead, a loss of pressure occurs over a period of time. In such conditions, the leak might be too small to allow conventional cement remediation because of the presence of the relatively large cement particles. One solution for such tight casing leaks is applying a casing patch over the leak area. This approach creates a restriction in the casing inside diameter (ID) that could potentially hinder the originally planned stimulation and completion processes, resulting in lower production rates. A solution without such disadvantages is a recently developed resin system that allows remediation of casing leaks with and without an injection rate.

Although epoxy resins have been used for cementing applications for decades, a recently developed resin system exhibits major benefits over resin used in the past. This new resin exhibits exceptional resistance to contamination including oil based and water based fluids, favorable mechanical properties, variable density, adjustable placement time, very low yield point as well as acid and abrasion resistance (Morris et al. 2014) . These properties, along with the availability of solids free designs, make the resin an ideal candidate for a wide range of remedial operations throughout the life of the well. In squeeze cementing operations, this resin can be applied in situations where conventional cement is unable to penetrate such as “tight” casing leaks or sustained casing pressure (Jones et al. 2013).

As per regulatory requirements, the 5.5 in. production string had to pass a mechanical integrity test (MIT) of 7700 psi for 30 minutes. After the pressure test failed, a test packer was run in the hole to determine the location of the leak. After running a testing packer, the leak was finally located in the multi-stage cementer tool / annular casing packer combo of the production casing at 6891 ft. An injection rate of 0.75 bpm at 7200 psi was established. Various solutions to fix the leak were considered and discussed. A regular cement squeeze was discarded right away because the small nature of the leak almost guaranteed that the relatively big cement particles in the cement slurry were going to provide little to no penetration for such a small leak, not to mention the inability to withstand the stimulation treatments. Other option considered for the leak was applying a casing patch over the leak area. This application had significant disadvantages including cost, the possibility of the casing patch not providing a complete seal of the leak resulting in a second remedial operation and most importantly, the reduction in the ID of the casing that even the thinnest of casing patches would produce. This ID reduction could affect the ability to run adequate frac plugs for “plug and perf” stimulation treatments and require the use of a smaller production packer, both resulting in lower production rates. After further discussion, a solids free resin system was chosen over the casing patch because of the many benefits that it offers.

JOB PLANNING

After the resin system was selected as the solution for the leak, lab testing was done to select the optimal recipe for the job. Due to the small nature of the leak and low injection rate, the resin rapidly comes in contact with the formation and heats up, requiring the use of the bottomhole static temperature (BHST) over the bottomhole circulation temperature (BHCT) as the design criteria. Using historical data from the area, a temperature gradient of 0.75°F/100 ft and the API formula for BHST, the design temperature was calculated at the multi-stage cementer tool to be 132°F. The resin reaction is temperature dependent, and an accurate BHST is the most critical design factor to ensure adequate placement time, compressive strength development and drill out time. The resin can be designed on a wide range of densities, from 6.5 – 16.0 lb/gal. A “neat” resin system can be designed from 9.1 – 9.3 lb/gal without any lightweight or weighting agents. Such a design was selected due to the fact that a solids free design permits flow and deeper penetration into tight channels and leaks without the risk of particle-bridging. For logistical considerations and as a safety factor, a volume of 10 bbl of resin was selected.

Lab Testing

The resin system can be designed on temperature ranging from 60 - 200°F. After determining a BHST of 132°F, laboratory testing was conducted to determine the optimum placement time using a squeeze temperature ramp and pump schedule. The thickening time (see Figure 1) was conducted at a bottom pressure of 5000 psi that includes a safety factor. To account for any adverse effects that may occur due to static shutdowns during pumping, a 1 hr shutdown was simulated to meet testing criteria for squeeze cementing applications. The resin is mixed in the laboratory by adding the individual components together in a regular blender used for cement mixing, but at a low shear in order to achieve a homogenous mixture. The final resin design and order of mixing is displayed on Table 1. While the Poisson’s ratio of the resin is closer to that of rubber, cement is closer to that of glass. In other words, cement is inherently stiff and this resin is inherently flexible. In order to determine the amount of time to wait on the resin 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” by 2” by 2” cube molds, and cured in a water bath at 132°F. After 24 hrs, the resin cubes were removed from the molds and a crush compressive strength test was attempted on each cubes. In Figure 2 a crush compressive strength chart is shown. Due to safety concerns, the tests were stopped at 10,000 psi without the resin failing. The mechanical compressive strain at that point was approximately 50%, illustrating the higher strain to failure values obtained with resin systems in comparison to cement.

Unlike cements which exhibit Bingham plastic rheological behavior, the resin system typically exhibits a Newtonian flow behavior (see Table 2), having little to no yield stress, allowing flow under extremely low forces (Jones et al. 2014). Rheological tests were conducted to ensure that the system exhibited these properties in order to squeeze it into the small leak in the multi-stage cementer tool. The viscosity of the resin was such that measurements using a Fann Yield Stress Adapter (FYSA) with Model 35 Viscometer provided a better rheological profile than the bob and sleeve configuration. The FYSA provides accurate rheological measurements of complex cement slurries and non-conventional zonal isolation systems such as resin (Gordon et al. 2007). The results are compiled on Table 2.

JOB EXECUTION

Due to the low injection rate of the leak, a "bradenhead" squeeze was selected as the remediation method. On a "bradenhead" squeeze there is no cementer retainer or packer reducing cost and the amount 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 el. 2006; Rike and Rike 1981). A composite bridge plug (CBP) topped with sand and cement was set approximately 179 ft below the leak at 7070 ft MD. Although the resin is resistant to contamination, the well fluid was replaced with fresh water to ensure density hierarchy and further decrease the possibility of contamination. Tubing was run pass the leak to approximately 7020 ft. Max pressure for the squeeze operation was set at 7200 psi. To mix the resin during the job, 330 gal chemical totes were delivered to location where a fork lift was used to gravity feed the required amounts of resin and hardener components into a batch mixer. During this stage, the resin was mixed by agitating the paddles of the batch mixer at medium speed until a clear and homogenous mixture was achieved. The accelerating component was available in 5 gal pails and was added to the resin system just before going downhole. At this point the final resin system was mixed for 10 minutes. The pumping schedule is summarized in Table 5 and Figure 3. The 10 bbl of resin were boosted to a regular cementing pump 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 1.5 minutes per stand or lower to ensure the balanced plug was not disturbed. Tubing stands were pulling dry, indicating fluids were balanced in the hole. Tubing was pulled to approximately 1000 ft above the calculated top of resin, and a foam wiper ball followed by a cleaning solution was pumped to remove any leftover resin out of the tubing. Subsequently, the tubing was reversed out with fresh water and pulled entirely out of the hole. The blind rams of the BOP were closed and the "bradenhead" squeeze operation started as shown on Figure 4. Approximately 13 bbl of fresh water were pumped to fill the casing because of the volume displaced after pulling the tubing out of the hole. A rapid increase in pressure indicated the casing was full and pressure was being applied to the entire column of fluid, pushing the resin treatment into the leak. Due to the solids free design of the resin, a squeeze pressure typical of a cement remedial operation is not going to be achieved. In this scenario there was a risk of over displacing the resin treatment and thus accurate displacement volumes were critical. A total of 6 bbl of resin were counted as being injected into the leak after the initial pressure indication. Subsequently, the squeeze operation was shut down and the well was shut-in after pressure had dropped to around 2000 psi.

RESIN DRILLOUT AND PRESSURE TEST

The well was shut-in with 2000 psi for 48 hrs to allow enough time for the resin to cure. A 4-5/8" junk mill with tungsten carbide cutters was run on 2-7/8" 6.5 lb/ft L-80 tubing. This size mill was 99.4% the drift of the 5.5" 20 lb/ft L-80 casing. The resin top was tagged at 6780 ft, indicating that approximately 4.6 bbl of resin were injected into the leak. The resin was drilled with 2000 lbs on bit to 7050 ft in around 4.5 hrs. The well was circulated 2 bottoms up, tubing was pulled out of the hole and the well was loaded with 13 bbl of fresh water. Using a reverse pump unit, the well was pressured up to 7700 psi and only 50 psi dropped in 30 min, passing the regulatory pressure requirements.

STIMULATION TREATMENT

After passing the regulatory pressure test of the casing, the well was successfully stimulated in 25 slickwater treatments. The summary of the stimulation operations can be found on Table 3 and Table 4.

CONCLUSION

The leak in the multi-stage cementing tool was repaired in one attempt using conventional cement equipment and techniques to squeeze a solids-free liquid resin system into the leak. After placement, the resin system cross-linked into an elastic, high-strength barrier capable of withstanding the forces generated during subsequent hydraulic fracturing operations. Wellbore integrity was restored without the use of casing patches, which would have reduced the inside diameter of the casing. The operator was able to perform the original stimulation treatment of the well without any signs of the leak. Through effective problem identification techniques, solution development and operational execution the use of resin technology is a valuable tool to both service companies and operators in well bore remediation efforts.

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Table 1 - Resin Design

Component	SG	Density (lb/gal)	Weight (lb)	%BWOR1	Volume (gal)
Resin	1.14	9.51	3042	100.0%	319.8
Hardener	1.02	8.51	821	27.0%	96.5
Accelerator	0.97	8.10	30	1.0%	3.8
				Total Volume (gal) =	420.0
				Total Volume (bbl) =	10.0
				Density (lb/gal) =	9.27

Table 2 - 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 - Stimulation Rates and Pressures

Stage #	Avg Rate (bpm)	Max Rate	Avg Pressure (psi)	Max Pressure (psi)	ISIP (psi)	5 min SIP (psi)
1	58.7	60.3	5,640	7,175	2,033	1,714
2	59.9	61.0	5,387	6,700	2,205	1,788
3	59.4	69.4	5,353	7,294	2,425	1,931
4	59.8	60.2	5,271	6,297	2,884	2,038
5	60.0	60.9	5,533	7,430	2,452	1,883
6	59.6	61.9	5,526	6,215	2,145	1,810
7	59.8	60.2	5,308	6,037	2,718	2,018
8	59.3	60.0	5,008	6,099	2,520	2,016
9	60.1	60.6	5,058	6,923	2,936	2,182
10	60.3	60.6	5,413	6,569	2,741	2,036
11	60.8	61.1	4,832	6,423	2,822	2,274
12	60.5	61.0	5,055	6,479	2,704	2,070
13	60.6	62.0	4,724	5,827	2,569	1,977
14	60.9	61.2	4,679	6,450	2,456	1,984
15	59.7	61.4	5,257	7,124	2,464	1,924
16	60.0	61.1	5,317	6,752	2,757	2,028
17	57.2	58.7	4,958	6,651	2,219	1,876
18	58.7	60.7	5,370	7,138	2,507	1,917
19	60.1	65.8	5,436	6,555	2,501	2,037
20	60.1	60.5	5,026	6,569	2,943	2,271
21	60.0	61.0	5,055	6,490	2,789	2,314
22	60.0	61.0	5,291	6,572	2,988	2,234
23	60.0	61.0	5,679	6,447	2,457	1,966
24	59.0	60.0	6,010	7,179	2,655	2,047
25	58.0	60.0	4,912	6,594	2,580	2,243

Table 4 - Stimulation Treatment Summary

Stage #	Frac Fluid (gal)	Total Prop (lb)	Prop Con (lb/gal)	Max Prop Con (lb/gal)	ISIP (psi)	PSI/Ft	5 min SIP (psi)	PSI/Ft
1	210,882	239,779	1.14	2.11	2,033	0.64	1,714	0.61
2	212,886	239,802	1.13	2.08	2,205	0.66	1,788	0.62
3	246,775	238,167	0.97	2.04	2,425	0.68	1,931	0.63
4	208,683	237,529	1.14	1.93	2,884	0.73	2,038	0.64
5	211,842	240,452	1.14	1.86	2,452	0.68	1,883	0.63
6	202,663	240,072	1.18	1.96	2,145	0.65	1,810	0.62
7	215,190	264,686	1.23	2.04	2,718	0.71	2,018	0.64
8	214,129	261,338	1.22	2.11	2,520	0.69	2,016	0.64
9	190,786	237,382	1.24	2.22	2,936	0.73	2,182	0.66
10	206,343	238,605	1.16	2.11	2,741	0.71	2,036	0.64
11	202,506	242,281	1.2	1.96	2,822	0.72	2,274	0.67
12	199,743	241,141	1.21	2.03	2,704	0.71	2,070	0.65
13	192,111	238,027	1.24	3.62	2,569	0.70	1,977	0.64
14	200,814	239,763	1.19	2.08	2,456	0.68	1,984	0.64
15	210,262	236,764	1.13	1.84	2,464	0.68	1,924	0.63
16	199,247	240,014	1.2	2.08	2,757	0.71	2,028	0.64
17	210,046	238,583	1.14	1.95	2,219	0.66	1,876	0.63
18	203,290	236,324	1.16	2.03	2,507	0.69	1,917	0.63
19	207,328	239,698	1.16	2.09	2,501	0.69	2,037	0.64
20	204,266	236,167	1.16	2.00	2,943	0.73	2,271	0.67
21	190,663	238,611	1.25	2.04	2,789	0.72	2,314	0.67
22	200,523	237,590	1.18	2.05	2,988	0.74	2,234	0.66
23	197,566	238,051	1.2	2.05	2,457	0.68	1,966	0.63
24	211,752	235,393	1.11	1.77	2,655	0.71	2,047	0.64
25	204,367	239,215	1.17	2.05	2,580	0.70	2,243	0.66

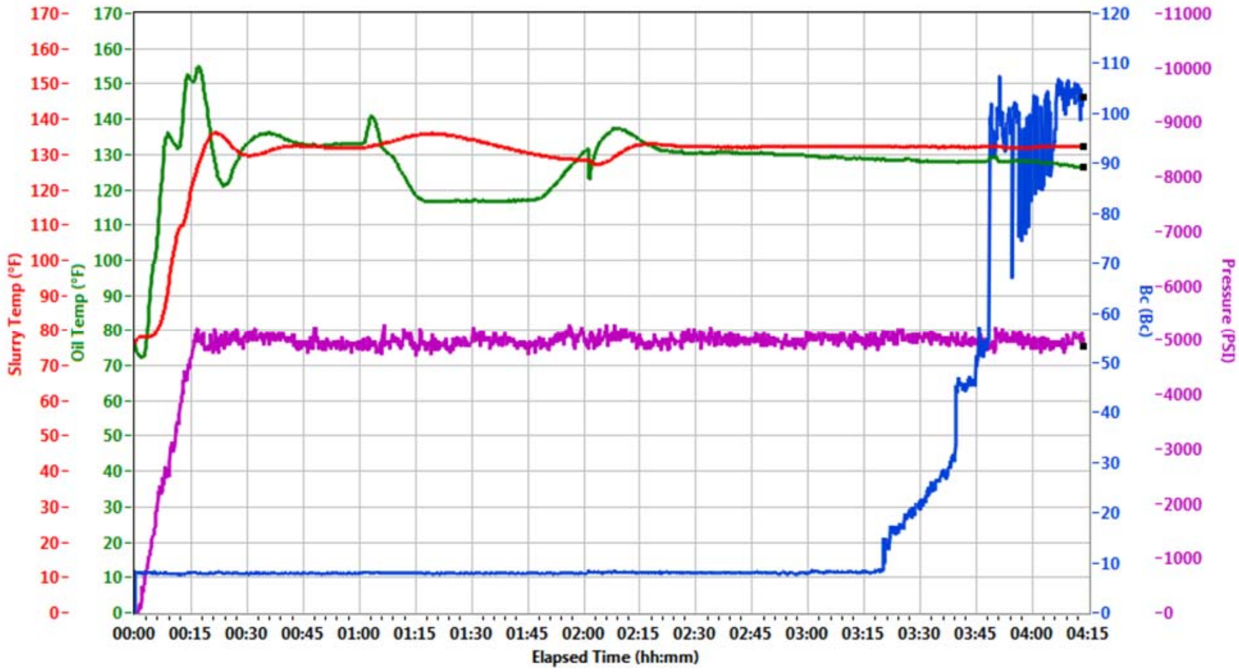

Figure 1 – Thickening time test of resin system

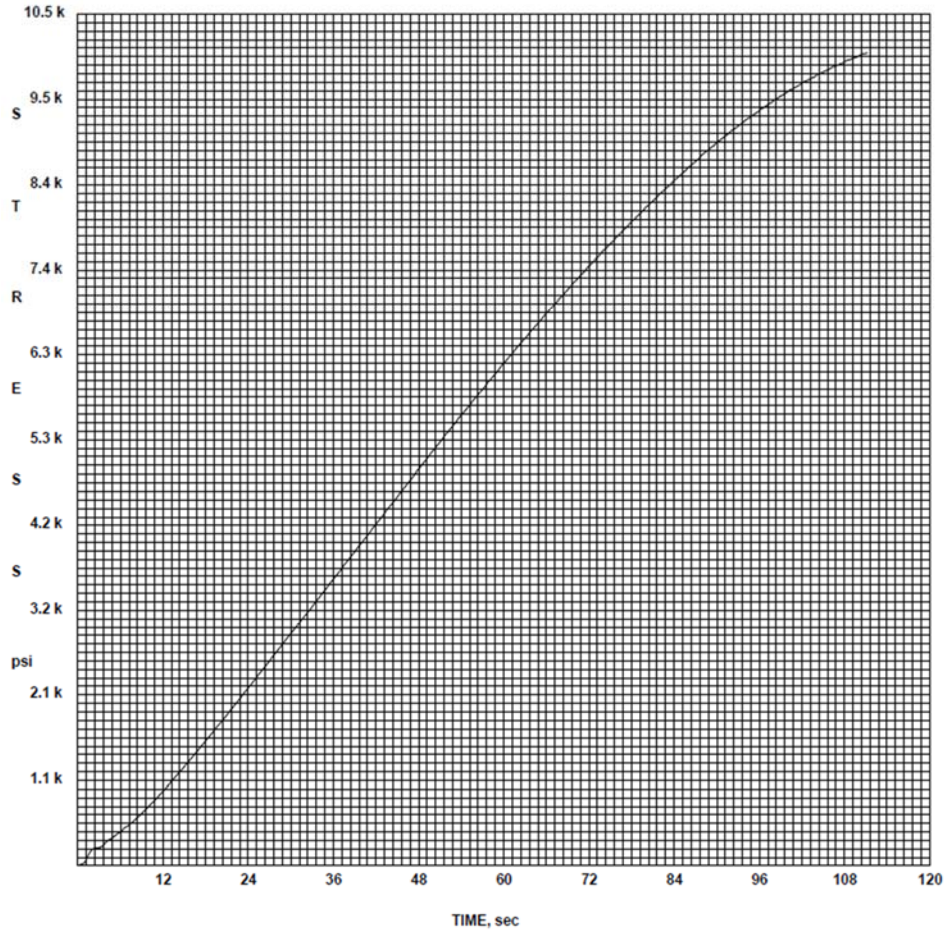

Figure 2 – Unconfined Crush Compressive Strength Test (Loading Rate = 4000 psi/min)

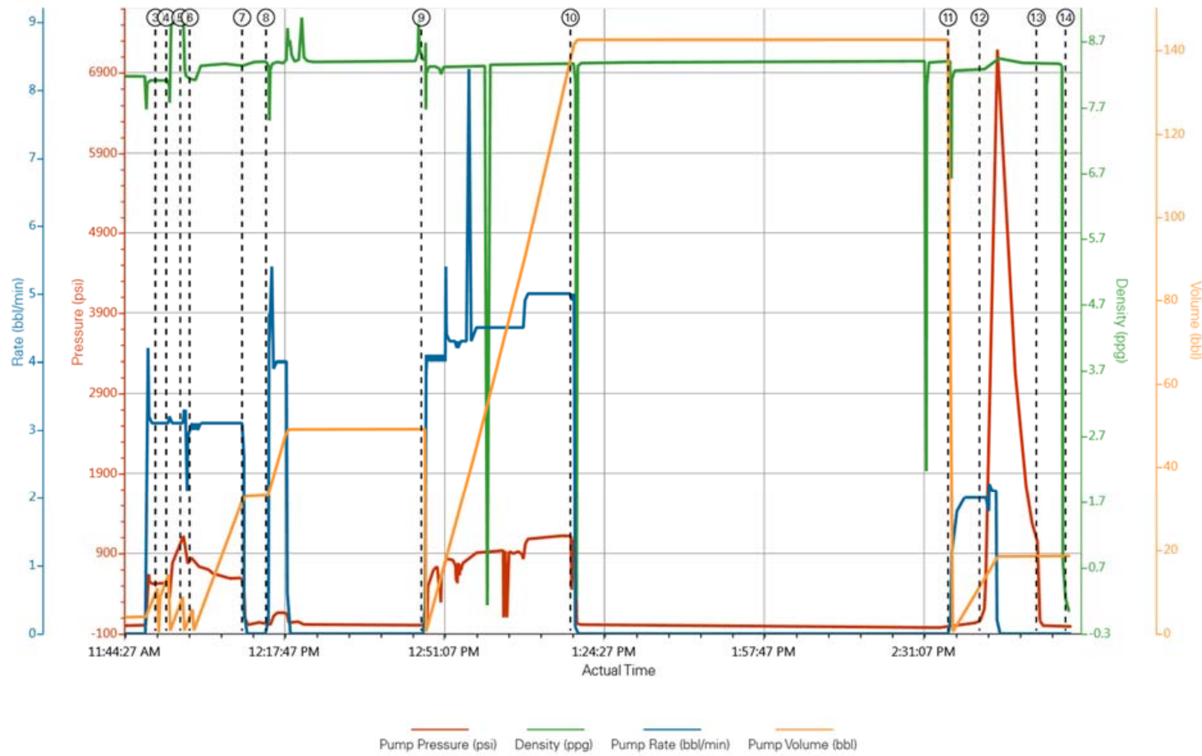

Figure 3 – Resin Squeeze Job Summary

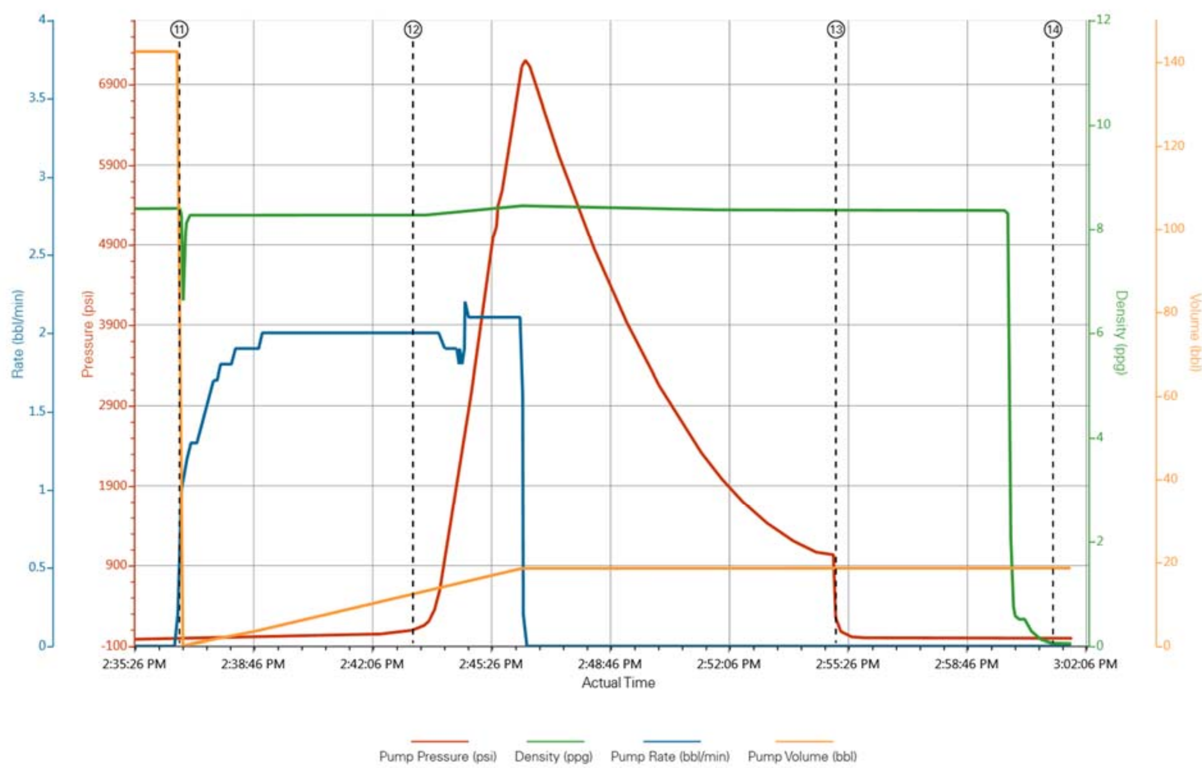

Figure 4 – Resin Bradenhead Squeeze Pressure Up

Table 5 - Cement Job Log for Figures 3 and 4

Event No.	Description	Time
1	Start Job	10:32:04
2	Test Lines	10:48:27
3	Pump Gel Spacer	11:51:25
4	Pump Resin	11:53:40
5	Pump Gel Spacer	11:56:37
6	Pump Fresh Water Displacement	11:58:35
7	Shutdown to Pick Up Tubing	12:09:30
8	Clean Lines and Equipment	12:14:29
9	Pump Foam Ball to Clean Tubing	12:46:54
10	Shutdown to POOH	13:18:00
11	Close Blind Rams and Fill Casing with Fresh Water	14:36:46
12	Squeeze 6 bbls in	14:43:19
13	Shut In Well with Pressure	14:55:11
14	End Job	15:01:16