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Stimulation of the RN-15/IDDP-2 Well at Reykjanes Attempting to Create an EGS System

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ABSTRACT

An overview is given of the stimulation activity carried out in the well RN-15/IDDP-2 at the Reykjanes geothermal field in southwest Iceland. The well was deepened to 4659 m (MD) from the 2507 m deep RN-15 production well in the time interval August 2016 to January 2017. The aim was both to create an EGS system underneath the conventional reservoir as well as to get into supercritical environment. The stimulation activity was divided into stages with the first stage consisting of short pressure and thermal shocking carried out at the end of the drilling operation. The second stage followed and concentrated mainly on cooling and thermal shocking on the deep section of the well. That stage ended in June 2017 by use of fluid blocking material to reduce fluid losses to the more permeable zones and to divert the pressure load to the less permeable zones. Preparation was made for hydraulic fracturing below the liner in the deepest part of the well as the third stage of stimulation but had to be abandoned. However, long term cooling from the top of the well and as far down as fluid blockers and permeability control allowed was maintained until August 2018 when the stimulation operation ended, and warmup was started to prepare the well for discharge testing.

The deepening of the well was basically drilled with total loss of circulation the whole time so all cuttings (60 m^3) were lost to fractures and fluid loss zones in the well. Though the cuttings are partly blocking the fractures it is considered that they can act as proppants as the well and formation warms-up. Number of fractures accepting fluid losses and the strength of the loss zones below 3000 m depth was more than had been expected before the drilling. Several loss zones were in the first 200 m interval below the casing (set at 2941 m) but the main zone was located at about 3360 m (MD). Affirmative loss zones were found down to at least 4550 m as observed from temperature profiles.

Simple injection step rate tests were used to measure the effectiveness of the stimulation activity. At the end of the drilling operation the injectivity index was estimated around 1.9 L/s per bar and it increased to about 3.1 L/s per bar during the first stimulation stage. Despite a lot of fluid blocking material had been pumped into the well, the injectivity index was estimated around 2.8 L/s per bar at the end of the stimulation activity.

Brief interpretation of temperature recovery during a warmup for thermal shocking indicate temperatures above 400°C in the deepest section of the well and close to 500°C near the bottom of the well.

1. INTRODUCTION

Drilling operations for deepening well RN-15/IDDP-2 at the Reykjanes field began 11th August 2016. The well had been drilled vertically in 2004 to 2507m depth with 13 3/8" production casing set to 794 m and a 12 ¼" open hole below. The main feed zone was at approximately 2360 m with formation temperature of ~290°C. The well supplied some 2-3 MW$_e$ to the Reykjanes power plant. The well is located north of the main up-flow zone of the Reykjanes field, so a slightly deviated drill hole was expected to intersect the up-flow at target depth of 5000 m. The rig was on site in July 2016 and the well was cooled and logged in preparation for deepening it to 3000 m before running casing with 9 7/8" and 9 5/8" diameters. Total circulation loss in the hole during deepening to 3000 m prevented return of drill cuttings to the surface, but that had been expected for that part of the operation. The well was deviated in the direction 210° at a kick off depth at 2750 m with the intention of building inclination to 16° from vertical. Depth of 3000 m was reached on August 22nd. Casing was run to 2941.4 m along with thermocouple cables and a fiberoptic cable attached to the outside of the casing to measure temperatures at various depths. Use of such cables outside casing is quite new in Iceland. The casing was cemented to surface with reverse cementing method completed on Sept. 6th, 2016 (Fridleifsson et al, 2018).

Drilling continued with downhole motor, MWD tool and an 8 1/2" bit. Circulation losses quickly increased to total losses in the first 200 m interval below the casing. About 12 cement plugs were set in attempts to cure the losses, but with limited results. At 3185 m a decision was taken to continue drilling in total circulation loss as deep as possible. The well was drilled to 4626 m and a 7" perforated liner was set to 4600 m as well as a sacrificial 7" casing to 1304 m that was cemented to surface. A T/P log measured after setting the liner on Jan. 3rd, 2017 gave 426°C and 340 bar at 4560 m depth which is above the critical point for seawater. A total of 13 coring runs were made during drilling that gave in average about 51% return. For the last cores the well was drilled with 6" bits through the liner down to 4659 m. Geophysical logs were obtained by special tripping with LWD tools to 4623 m before the liner was inserted.

At end of drilling short stimulation with thermal cycling and pressurization was carried out that increased the indicated injectivity for the well to about 3.1 L/s per bar. The drilling operation was completed on January 25th, 2017 by installing a 3 ½" pipe to about 4589 m depth for further stimulation. Below the stimulation effort is described briefly from the end of drilling in January 2017 until the warmup of the well was started in August 2018 as a preparation for flow testing in 2019 (Sigurdsson, 2019).

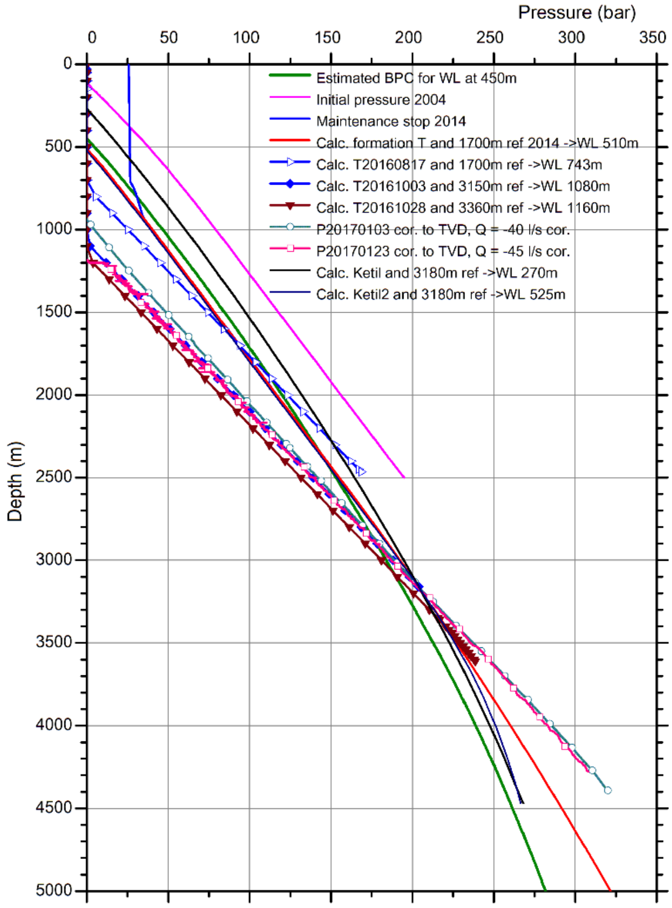

Figure 1. Pressure profiles measured and calculated from corresponding temperature profiles for different reference levels.

2. PRESSURE CONDITIONS IN THE WELL

In the old well RN-15 three main feed points had been determined at depths around 1680 m, 1720 m, and 2360 m. Other less active feeds had also been identified over the open interval in the well. When the well was warming up after its drilling in 2004 the controlling pressure point (pivot point) was determined to be near or just below 1700 m depth in the well. In June 2016 measured pressure at 1700 m depth was 93.3 bar. For that pressure the liquid brine level in the well was calculated to be at 516 m assuming interpreted formation temperature or at 490 m using the corresponding measured temperature in the well. After killing the well with freshwater and cooling it down as was done in the beginning of the deepening operation the liquid level in the well was calculated at 785 m assuming brine in the well and at 748 m assuming freshwater in the well, which corresponded well with what was observed. Due to the depth to the liquid level and with the known feeds, it was clear that drilling for the 9-5/8” production casing to 3000 m depth would be in total loss of circulation.

Interpretation from MT-resistivity profiles indicated that porosity would decrease with depth and likely be in the 1 % range at 3500 m and deeper. It was assumed that permeability would decrease correspondingly with depth, so circulation might be gained after cementing the production casing. The production casing was cemented to 2941 m depth on September 5, 2016 and when drilling started again circulation was obtained. However, shortly into the drilling circulation losses started and increased to total losses. Injectivity as low as 0.3 kg/s per bar could be enough to cause considerable losses with the 100-110 bar overpressure from the water column in the wellbore. Some small fracturing may have occurred from this overpressure enhancing the losses. Several cementing plugs (12 plugs) were set in the interval 2941-3185 m to cure the circulation losses, but with limited success (Weisenberg et al., 2017).

On October 3rd, 2016 the well depth was 3178 m, but the main losses were estimated around 3150 m depth (3143 m TVD). That day short step rate test was carried out and pressure and temperature profiles measured. Moving the pivot point down to this depth along the hydraulic gradient from the above geothermal system, as the shallower feeds had been cemented behind the casing, a liquid level was calculated to be at about 1080 m depth (Figure 1). The liquid level was observed around 835 m with about 20 L/s injection. The injectivity index was interpreted from the step rate test to be about 1.2 L/s per bar. Correcting for the injection would bring the measured liquid level 170-200 m deeper (1005-1035 m). The stable liquid level could be a little lower and the actual location of the pivot point higher which would make the difference between observed and calculated liquid levels less.

Another short step rate test was carried out on October 26th, 2016 when the well depth was 3648 m. At that time the main loss zone was assumed to be at about 3360 m (3343 m TVD). Moving the reference pressure (pivot point) down to that depth along the hydraulic gradient and calculate for the liquid level gave it at about 1161 m depth. From the pressure profile the liquid level was observed at around 1025 m with about 20 L/s injection. The injection index was estimated about 1.5 L/s per bar from the step rate test. Correcting for the injection lowers the observed liquid level down by at least 135 m or to about 1160 m.

On November 9th, 2016 when the well depth was 3865 m the liquid level was observed at similar depth for similar injection rates. This is interpreted such that the pressure conditions in the well down to at least 3700-3900 m follow the average conditions observed in the above geothermal reservoir. It is also suggested that the pressure conditions, deeper and into the supercritical part of the well, are not much different. That appears to be supported by the pressure measurements carried out near the end of drilling and at completion after the first stage of stimulation in January 2017 (Figure 1).

3. FIRST STAGE OF STIMULATION

3.1 The stimulation operation

The first stage in the stimulation of the well was carried out at the end of the drilling operation and after the final coring runs. The rig equipment was used for this first stage. The stimulation program consisted of short steps of pressure and thermal shocking. For the first half a day the pumping rate was oscillated between around 45 L/s, which had been the regular circulation rate during drilling, and up to full capacity of the rig pumps (110-115 L/s), while the mud tanks were drained (Figure 2). Then the pumping rate was reduced to former level while water was collected in the mud tanks and then the step was repeated. For logging and injectivity tests the injection rate was brought down to levels corresponding to conditions during earlier tests to make comparison between test easier. After the step rate test the well was closed for about 18 hours for warmup period followed with about 12 hours cooling period where pumping was oscillated similarly as before. This was repeated once more before the well was logged for temperature, pressure and flow rate (spinner), and this operation ended with a step rate injection test.

Figure 2 gives an overview of the pumping rate applied during this stimulation stage. Also seen on the figure is the oscillation of the rate and recording of the kill line pressure. Though the kill line pressure shows a positive reading during the highest pumping rates it is not considered to be caused by a water column being at the top of the well. Rather it is thought that interference between the connection spouts on the wellhead are causing this reading. Furthermore, the lowest injectivity at that time would indicate that the water column could only rise about 650 m which was over 300 m short of reaching the wellhead.

In Figure 3 the results for the injectivity are shown for both injection and falloff steps. There the data has been filtered slightly to make it more readable so the approaching injectivity index can be read from the graph. The results indicate that the injectivity for the well improved considerably from that at the end of drilling from about 1.7 L/s per bar to 2.9 L/s per bar during the stimulation and to 3.1 L/s per bar at the end of this stimulation stage.

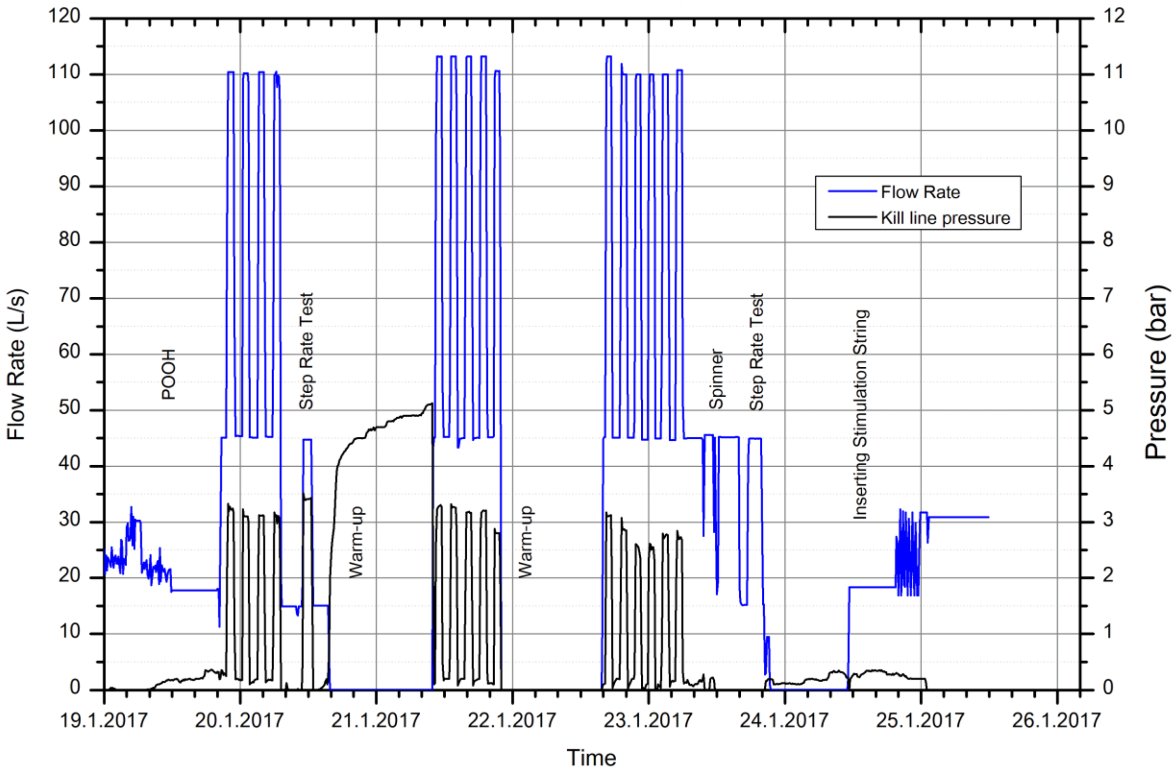

Figure 2. Pumping rate during the final days of the drilling operation. The oscillating injection rate during the stimulation and the warmup periods in between. The stimulation stage-1 ended by inserting the 3-1/2” stimulation string.

3.2 What was stimulated

At end of drilling the injectivity in the well was similar as had been estimated from logs at end of October to beginning of November 2016 (1.4 to 2.0 L/s per bar), when the well was 3648-3865 m deep. Given loss of cuttings (29-37 m^3) to the main feeds from the additional 800-1000 m of drilled hole this seemed reasonable. As the well was drilled basically with total loss of circulation the amount of cuttings lost to the formation is about 60 m^3. The cuttings have accumulated in the main feeds and smaller fractures and may have been pushed further out from the well during this stage of stimulation. There the cuttings may act as proppants. This process can have contributed to nearly doubling the injectivity during the first stage of stimulation.

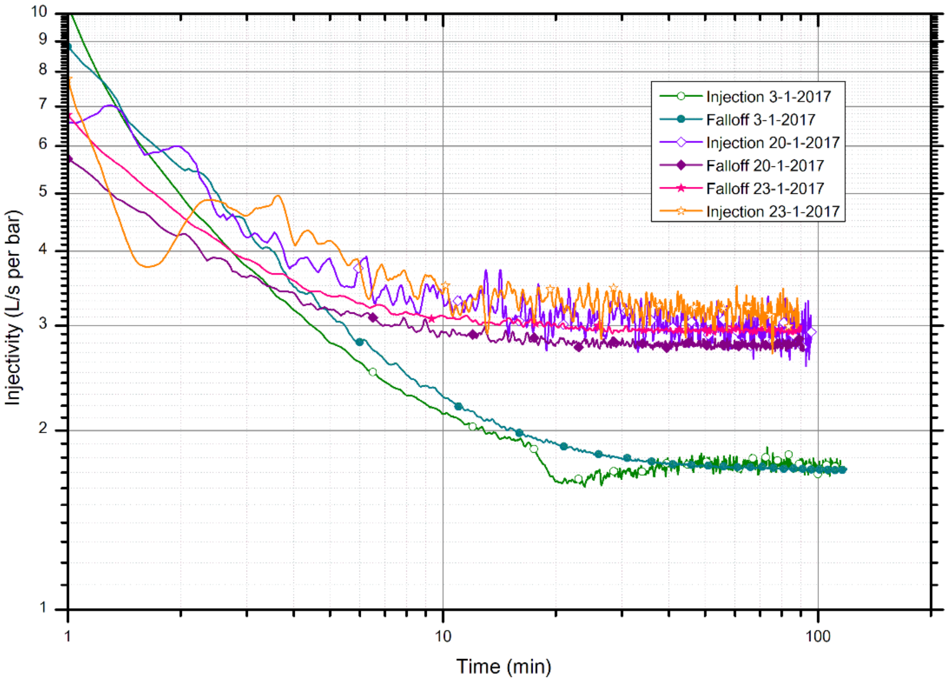

Figure 3. Stabilization of the step rate changes indicating the approximate prevailing injectivity. The data has been filtered slightly to reduce the noise in it and make it more readable.

Figure 4 shows four temperature profiles that were measured during the latest stage of the drilling operation. For the down profile from January 3rd, 2017, when the well depth was 4626 m, the flow rate down the well has been roughly estimated from the change in temperature gradients between the main feeds that can be identified from the profiles (3340-3360 m, ~4200 m, ~4370 m, 4550 m) (Carslaw and Jaeger, 1959). This estimate indicates that most of the injected water is lost to feeds above 3400 m depth (93%) and only about 6-7% of the injectate at wellhead goes to the deeper part of the well. Furthermore, in that run the highest temperature 426°C was recorded at 4560 m depth indicating, along with the pressure, supercritical conditions in the formation at the deepest part of the well. For the profile measured on January 23rd, 2017 after the first stimulation stage, it is not clear if the hump between 3400-4200 m is representative for the well conditions as injection rate was changed from about 15 L/s to 45 L/s when the tool was at 1200 m depth. Small inflow that had developed at that time at around 2310 m from casing damage could influence this behavior. However, the main shape of the temperature profiles before and after the stimulation is about the same, indicating that this stimulation stage has mainly affected the feeds above 3400 m depth. The deeper feeds below 3400 m have not been affected much by the stimulation and still have relatively low permeability.

Referring back to Figure 1 the pressure profiles from January 3rd and 23rd, 2017 have been plotted after being corrected to TVD and for effect of injection rates. As can be seen in the figure and read for the profiles from the indicated water level and intercept with the hydraulic gradient from the shallower geothermal system, that the reference pressure point (pivot point) has moved up again. The profiles fall on an earlier profile with the reference point at 3150 m depth (3143 m TVD), which indicates that the stimulation mainly affected the depth interval 2940-3360 m. The feeds in the interval 2940-3185 m where 12 cement plugs were set in attempt to cure circulation losses may have been mostly affected by this first stage of stimulation.

4. SECOND STAGE OF STIMULATION

4.1 Pre-drilling plan

In planning the deep drilling, it was expected that permeability would decrease with depth in a similar manner as predicted reduction of porosity from MT-resistivity profiles in the area. Therefore, it was considered likely that the well could be "dry" below 3000-3500 m depth. It was also predicted that temperature would increase with depth so for a soft stimulation it was planned to put in the well a stimulation string (tube) and circulate cold water through it for a minimum of some months in order to create enough temperature difference for contraction fractures to form. Available stimulation methods had been scanned for applicability to Reykjanes and some simulation made for the applicability of cooling to act as a stimulation process. The results from that simulation were promising regarding effective cooling of the rock formations leading to fracturing (Peter-Borie et al., 2017, Peter-Borie et al., 2018).

When the well had been drilled it was found that there were actually some feeds in the deeper part of the well (Figure 4). However, only a small fraction (6-7%) of the injected fluid at the top of the well was estimated to get to the feeds below 3400 m depth. Therefore, it was decided to stay with the pre-drilling plan and insert the stimulation string to near the deeper end of the liner in order to get more cooling water to the deepest part of the well. The drilling operation was completed by inserting a 3-1/2" open end drill string to 4589 m depth. The string was hung at the wellhead in a special pre-made clamp that allowed access both to the string and the annulus. The activity during this second stage of stimulation would focus on the deeper part of the well. The activity would involve long term cooling and cyclic thermal shocking. If feasible the third stimulation stage could occur after the stimulation string had been pulled out of the hole.

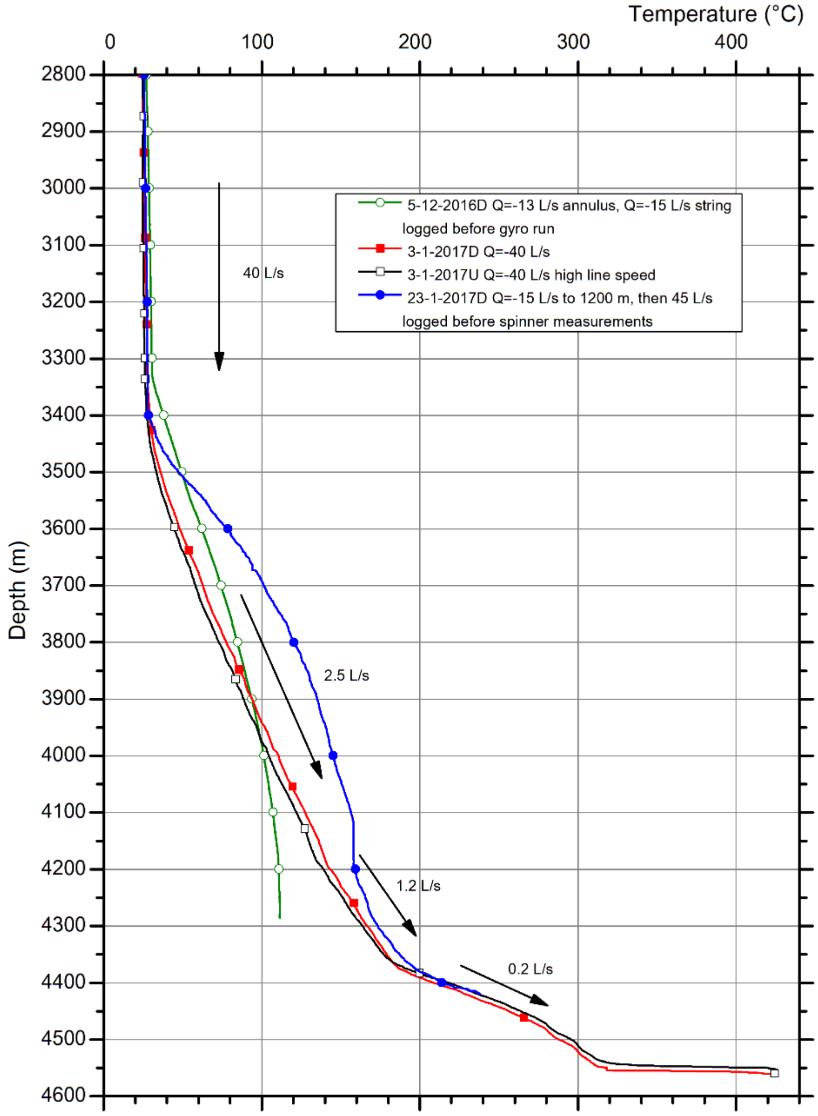

Figure 4. Temperature profiles measured during the last weeks of the drilling operation. Profiles from January 3rd, 2017 show the highest measured temperature in the well near bottom at 426°C. For that profile rough division of the injected water is given to the main observed feeds.

4.2 The first months of the stimulation operation

To maintain safety on the well and to prevent the casing for premature overheating and expansion a small injection rate would be kept on the annulus at all time. It was estimated from simple conduction calculations that 3 L/s injection on the annulus would be sufficient for that purpose, but to begin with that rate was defined around 5 L/s which should not cool the well much below 3400 m (HOLA simulator, Bjornsson et al., 1993). A rough estimate of the warmup of the well during heating period indicated that at depth the well could recover up to 70-80% of the formation temperature in 5 days (Kutasov and Eppelbaum, 2015). That would though depend on how active the cooling had already been at depth. Further estimates indicated that the well could be cooled down to former state with 40-50 l/s injection in less than 10 days. The first thermal shocking trials were based on those estimates.

Figure 5 gives an overview of the injection into the well during the second stage of stimulation from end of drilling to start of warmup and rough division between rate on annulus and string. Figure 6 zooms in on the period where the drill rig pumps were used for high rate injection. After the drilling operation in January 2017 about 5 L/s were allowed to flow on the annulus to keep the cased part of the well cool while pumps were prepared to be connected to the stimulation string. By the end of January 2017, a pump had been connected that delivered about 11.5 L/s into the string at 16-18 bar while a similar amount was free flowing on the annulus with pressure support from the water supply system. However, the free flow to the annulus dropped to about 5 L/s when that support had to be disconnected. The green curve on Figure 5 gives the total rate to both stimulation string and annulus while the blue curve shows the rate supplied by the pump, after it was connected to an acquisition system. The pump mostly pumped into the string, but at the low rates it went to the annulus. During the next weeks few modifications of the connections to the well were tried in attempts to increase the total rate to the well without much success. The aim was to be able to pump 35-40 L/s into the well and thereof up to 15 L/s through the string to the deepest part of the well. The struggle with the pumps ended in May 2017 when use of the rig pumps became available.

In line with earlier estimates with 10 days pumping and 5 days warmup two thermal cycles for the deep part of the well can be seen in Figure 5 during these first months (March 20-25 and April 29th to May 8th). Another two days cycle was on April 18th during one of the connection modifications. Generally, as the injection rate to the annulus was lower than hoped for the injection time was made longer to get the cooling down the well. In May a contract was made to use the rig pumps to enhance the stimulation process.

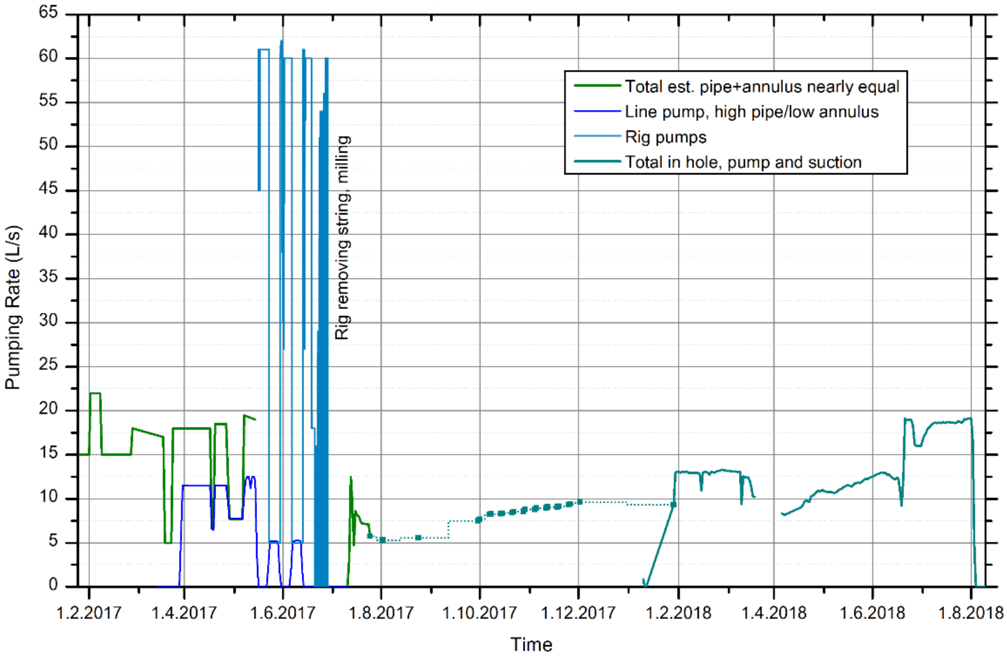

Figure 5. Injection rates into the well during long term cooling from end of drilling operation January 25th, 2017 and to start of warmup August 3rd, 2018.

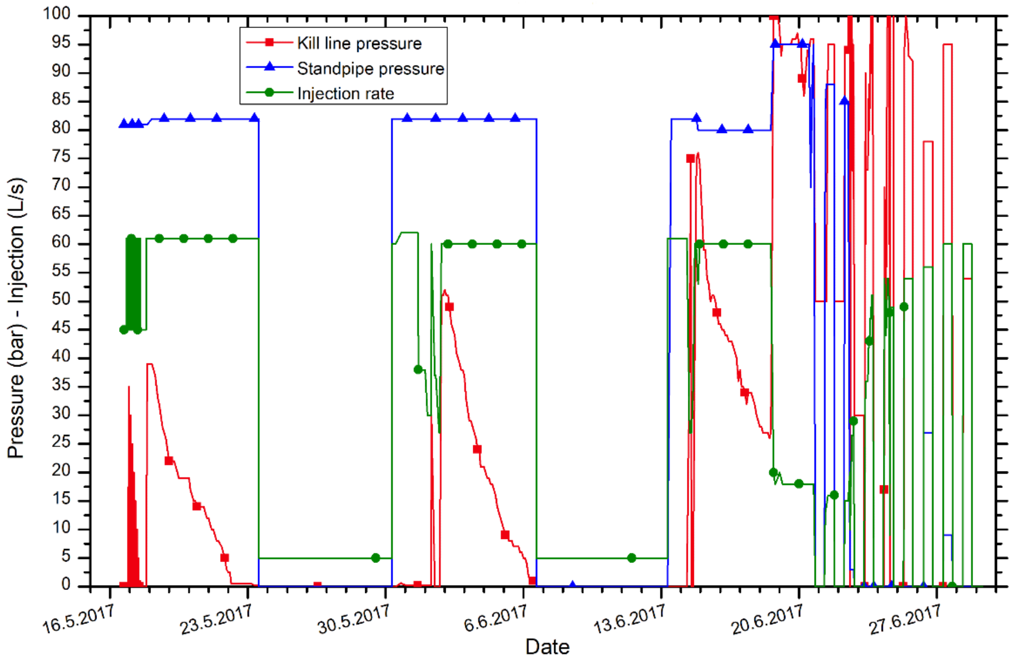

Figure 6. Injection rates and pressures as zoomed in on the period where the rig pumps were used along with fluid loss blocking materials.

4.3 Stimulation with the rig pumps

Contract for using the rig equipment was for 7 days pumping shifts and 7 days off for about one-month time. The injection was transferred to the rig pumps on May 16th and the injection rate increased so that about 15 L/s went to the string at about 82 bar standpipe pressure and about 45 L/s on the annulus, totaling about 60 L/s. Figure 6 gives a better overview of the conditions at wellhead during the use of the rig equipment. On site was a fluid blocker material (LCM) with a melt point or break down point at 180°C. Knowing that most of the flow into the annulus was lost above 3400 m depth, there was a will to test the fluid blocker in an attempt to get more cooling effect and higher-pressure head on the deeper part of the well.

Leakage in the well was assumed greater than usual losses at casing depths so for the first round it was decided to prepare double the recommended normal batch of the fluid blocker (two pallets, 1430 kg). However, it turned out not so easy to mix up this fibrous material in water, so the two pallets were basically vacuumed into the annulus with about 30 L/s pumping, but at the same time the pumping on the string was maintained at about 15 L/s. After the material was in the well the pumping rates were kept the same for over an hour to allow the material to get to 3350 m. When the injection rate was to be increased it was found that the supply system had reduced capacity due to pump failure. Therefore, while maintaining the rate on the string, the rate to the annulus was cycled hourly between 30-46 L/s. This was maintained during the night, but the pump was replaced the next morning. After about an hour of full injection a pressure up to 35 bar was observed on the kill line indicating that the fluid blocker was working, resulting in raising the water level from about 1000 m depth to the surface (100 bar) and further by creating pressure on the kill line. The day after additional 30 sacks were vacuumed into the annulus, but on the next sack water was observed. After about an hour the pump rate into the annulus was increased to about 46 L/s while the rate to the string had been kept the same. A pressure of 38-39 bar was observed on the annulus. For the rest of this first week with the rig equipment the injection rates were kept steady while the kill line pressure declined slowly.

After the first week with the rig pumps the injection rate was taken slowly down and observed that the standpipe pressure was mainly caused by resistance in the string, but at about 10 L/s it was basically down to zero. Injection to the annulus was transferred to site pump and adjusted to 5 L/s to keep the casing cool during the week off from the rig equipment. During this week four temperature recovery measurements were carried out inside the string with a Kuster mechanical gauge (125-440°C). The measuring locations were selected to be where earlier measurements had shown gradients in the well. The first measuring points were taken about three hours after shut-in. The profiles show a cooling point near 4500m which was hardly noticeable in earlier measurements (Figure 9). This loss zone has been accepting a lot of water during the pumping week and maybe also from earlier injection. Furthermore, the profiles indicate that some water is going to some zones below 4565m, possibly to a loss zone in the cored bottom. It was also observed from the black cards from the temperature tool that the loss zone around 4200 m had been accepting water and was colder than the measuring point at 4250 m. The loss to 4200 m was though likely less than indicated to be around 4500 m as it did not show up until in the measurement from May 26th and was then influencing the warmup rate at 4250 m.

In the last temperature run (29-5-2017) the tool was not stopped for readings at the hot point at 4450 m. That point is therefore hotter than shown and probably as hot as the deepest one. Reason for not stopping the gauge was to spare the tool in hope of getting the deeper points.

The second week with the rig pumps was started at about the same rates as earlier i.e. about 15 L/s on the string and about 45 L/s on the annulus. Standpipe pressure went to just over 80 bar as before while kill line pressure was zero. After one day of injection a mud suction pump was made ready and the fluid blocker mixed in a mixing tank and pumped to the annulus. During the night and to early next day two pallets and the remains from last pallet were mixed and pumped into the annulus. During this the rate on the string was kept about 15 L/s, but the rate on the annulus was about 24 L/s which had to be lowered to 15 L/s to keep suction on it. Total of five pallets of fluid blocker had then been put into the annulus and on site were four pallets left. When the fluid blocker was in the well the rate on the annulus was increased slowly to about 45 l/s and the kill line pressure rose to just over 50 bar. In 24 hours, it had declined to just under 40 bar. This pressure decline was a little bit faster than during the earlier one.

The indication from the rig pumping cycles was that the fluid blocker was blocking the main loss zones and indicating that good amount of water was going into the formation in the deepest part of the well. The injectivity at end of the first stage of stimulation was around 3.1 L/s per bar and after putting in the fluid blocker it was lowered to less than 0.5 L/s per bar. So the injectivity to the zones like around 4500 m appeared to be on that order. Furthermore, the cooling during the earlier injections appears to have been more around 4500 m than around the known loss point at 4200 m.

The third pumping cycle with the rig pumps started on June 13th. During the first 24 hours injection was about 61 L/s and as before about 15 L/s to the string and the remainder to the annulus. The standpipe pressure went up to about 82 bar, while the kill line pressure was zero. The next morning it was started to put into the annulus more fluid block material with pumping on the annulus taken down to about 12 L/s. After about 20 sacks had been pumped in, a pressure kick was observed on the annulus (at 10:30) so the injection of blocker was stopped. The first kick was just over 30 bar and lasted maybe for five minutes and then dropped to zero pressure on the annulus. Several pressure kicks followed where the kill line pressure went up to about 75 bar and lasted for some minutes before it dropped to zero again (pumping on annulus about 12 L/s). At noon this behavior had stopped and the injection rate on annulus was increased to 20 L/s but kill line pressure stayed at zero. At around 15:00 hours the rate was increased to 45 L/s (+ the 15 L/s that was on the string) and a pressure of 44 bar was observed on the kill line. Two hour later the rest of the mix in the mixing tank (about 5 sacks) were injected and the rate taken back up to 45+15 L/s. Kill line pressure went up to 75-76 bar. The pumping was then kept steady and the kill line pressure started to decline. A small decrease in the rate on the string lowered the standpipe pressure to around 80 bar.

The third pumping cycle with the rig pumps was to end on June 20th, 2017, but by middle of June it had been decided to attempt a hydraulic stimulation with packer in the interval below the liner (~4630 m). After June 20th pumping would then continue on day shifts but the well would warm-up during the nights. In this manner the well would be kept cold until equipment for the hydraulic fracturing were on site. This would give access to the rig pumps for at least one week more so in the afternoon on June 18th additional fluid blocking material (6 sacks) was added into the well through the annulus. After that the annulus rate dropped to 2-4 L/s from about 45 L/s earlier at the cutoff pressure set for the pumps at about 110 bar, actual pressure at wellhead about 10 bar lower. The day after the pumping on the annulus was kept similar (around 3 L/s), which had been estimated before the stimulation stages to be enough to keep the cased hole cold. The annulus or kill line pressure did not drop as in previous steps after adding the fluid blocker. On June 20th the pumping was similar, but in the evening the contracted pumping period for that week ended so no pumping was during the next nights. On the day shift next day the pumping conditions were similar as the days before with limited rate into the annulus (3-4 L/s) with kill line pressure around 95 bar and about 15 L/s on the string. On June 22nd it was decided to try to break through the blockage and see if new fractures could be created or opened. At about 1400 hours the pressure limit for the rig pumps was raised to 180 bar and pumping started. The pumps were stopped when the kill line pressure was 170 bar. The pressure was holding there for about 15 minutes but started then to drop and fell to zero. Injection was set at 10 L/s to the kill line and pressure went to 165 bar and then started to drop and fell to 115 bar. When the pressure had dropped to 95 bar the injection into the annulus was increased. The rate to the annulus was up to 19 L/s at 83 bar pressures on the kill line when the pumps were stopped that evening. During the next day shifts the rate to the annulus was increased as the kill line pressure decreased. During those days the pumping on the string was around 9-10 L/s so the standpipe pressure was around zero. The second stimulation stage ended on June 29th, 2017 when the rig started to pull the stimulation string or tube out of the hole.

5. THIRD STAGE OF STIMULATION

The third stimulation stage was decided by middle of June involving setting a packer at about 463 m for hydraulic fracturing below the liner in the 6” wide bottom section of the well. When the rig pulled on the 3-1/2” string it turned out to be stuck in the well. The string was freed and pulled out on July 2nd. It was found that there were casing damages in the interval 2307-2380 m so on July 12th attempts for hydraulic fracturing had to be abandoned and the rig moved off the well.

For the next months the injection to the well was on the wellhead and only 5-7 L/s (Figure 5). The onsite suction pumps did not have much higher capacity, but this was enough to keep the cased part of the well cool while possible actions to intervene with the casing damage were reviewed. At the same time, it can be said that the deeper part of the well had started to warmup as minimal fraction of this flow rate would go deeper than about 3400 m. In 2018 it became clear that funds to attempt casing repairs were not available. Modifications on the connections between the water supply system and the wellhead had increased the injection rate to 10-12 L/s and even up to 18 L/s which could have caused some cooling in the deeper part of the well.

On August 2nd, 2018 a mixture of brine and condensate from the power plant injection pipe line was opened to well RN-15/IDDP-2. The rate from the pipe line was adjusted to about 15-20 L/s and temperature around 70°C. The rate from the fresh water supply system to the well was taken down to about 7 L/s and the morning after the fresh water injection was stopped. The warmup of the whole well was started.

A short step rate injection test was carried out in September 2018, just over a month into the warmup period. The injection to the well from the injection system had by then been increased to about 50 L/s and temperature around 130°C. The test was done by shutting off the injection for some time and then open for the injection again. The results for the injectivity are shown in Figure 7 on top of the former similar results. The estimated injectivity index is 2.7 to 2.9 L/s per bar which is not much lower than at end of the first stimulation stage. Bearing in mind that considerable amount of fluid blocking material had been put into the well, which does not break down until temperature is 180°C or higher, the injectivity can be considered fairly good.

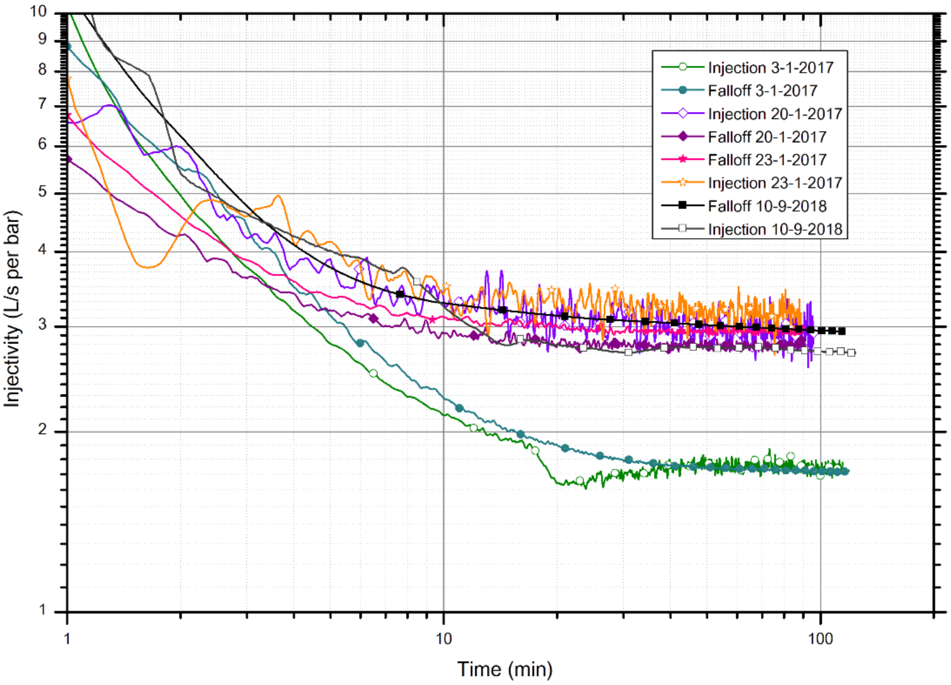

Figure 7. Stabilization of the step rate changes indicating the approximate prevailing injectivity. The data has been filtered slightly to reduce the noise in it and make it more readable. Results from earlier step rate tests shown for comparison.

6. ESTIMATED FORMATION TEMPERATURE

During a weeklong stop in injection to the deeper section of the well in May 2017, four temperature measuring runs were performed in order to see the warmup rate at selected depths (Figure 9). The measurements were made with a mechanical Kuster tool (bimetal) with temperature range 125°C-444°C. The tool marks on a black card and temperature is determined from calibration tables corresponding to the deflection from a base line. The measuring points or depths were selected to be where temperature gradients were observed in the well during earlier measurements. In that way it was tried to stay away from known loss zones that were heavily influenced by the cooling from the stimulation. As the measurements were carried out inside the stimulation string the tool had to pass easily through the string as well as have reasonably high temperature tolerance. The old Kuster tool fulfilled those criteria's, but it could not give continuous depth recording and had to be stopped at selected depths for recording.

As mention earlier the run on May 23rd, 2017 (Figure 9) indicates that the cooling through the stimulation string and to the deeper section of the well has been effective. The following runs give an indication of the warmup rate and can be extrapolated with suitable function to estimate the static formation temperature (SFT). The warmup rate is a measure of how the wellbore fluid tends to equilibrate with the formation temperature over some period of time (normally months). The measurements show that considerable amount of deep injection fluid has entered loss zone around 4500 m which is slightly higher up in the well than indicated in earlier measurements close to 4550 m (Figure 9). Also seen in the black cards is that the loss zone around 4200 m depth has accepted good amount of fluid and that the cooling may influence the warmup rate measured at 4250 m.

First attempt to estimate SFT from these temperature runs was made in a Working Document from September 2017 (Tulinius, 2017). There the Horner method was used to extrapolate the temperature measurements to determine the static or prevailing formation temperature. The Horner method depends strongly on circulation time or effective cooling time as do many similar methods. However, it can be difficult to determine the effective cooling time in complicated actual operations and hence considerable error can be introduced to the SFT estimate. Similarly, methods that require knowledge of thermophysical properties of fluid and formation may not be applicable in many actual cases where that information are not available. Here methods that use only measured temperature and shut-in time are considered to estimate the SFT.

One method that fulfils that requirements is called "least squares rational polynomial method (LSRPM)" (Wong-Loya et al., 2015). The first order equation for that model is given below where *T* is temperature, *a, b, c*, are fitting constants and *t* is shut-in time.

$$T = \frac{a+bt}{1+ct} \qquad (1)$$

The method gives possibilities to estimate errors in the fitting parameters and in such gives more weight to the later measurements. The method requires at least 4 readings to work, but additional readings would define better the thermal recovery process and the asymptotic value. The results are shown in Figure 8.

Another model that fulfils the above requirements has a resemblance with the Horner method but is modified such that it meets all the time boundary conditions (CYK) (Liu et al., 2016). Parameters are defined as for equation 1.

$$T = a + b\,log\left[\frac{1}{(1+ct)} + 1\right] \qquad (2)$$

This equation can characterize the temperature recovery function in general and can be fitted to the data with a least square method. For few data points as is the case here (generally only 4) a use of a least square method with weighting procedure where increasing weight could be applied to the later data would work better. Here only a simple least square method is used (OLS) so in some instances it can be seen from the shape of the matching curve that the SFT is underestimated. In those cases, the results give the minimum estimate for the SFT.

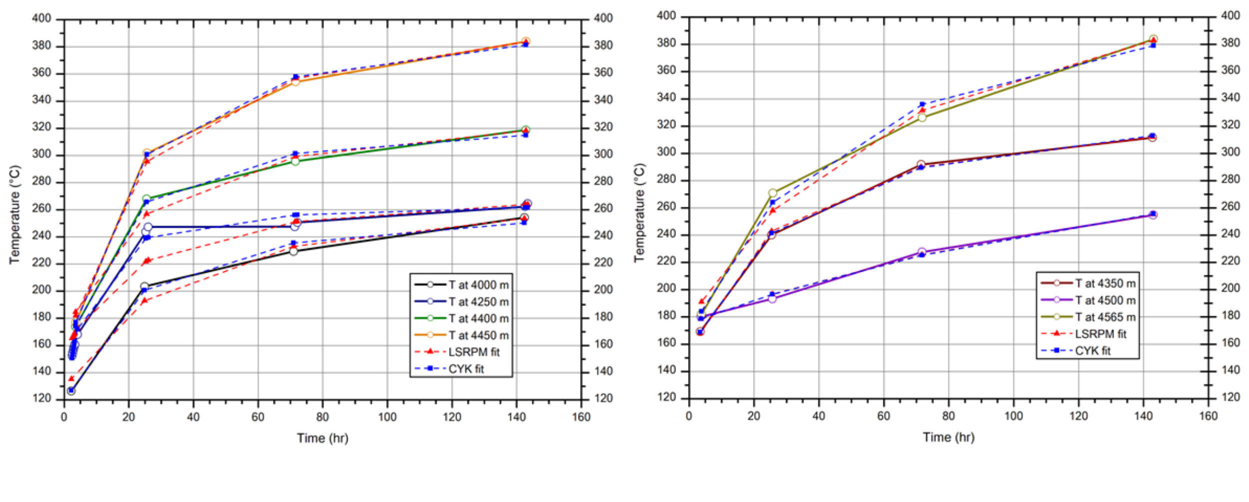

Figure 8. Temperature recovery measured at indicated depths and matches to the data using the LSRPM and CYK models. Note that the last data point for the 4450 m data is estimated.

For the matches to the temperature recovery data as shown in Figure 8 the LSRPM fit to the latest data points is generally good and the shape of the fit may indicate in general how good the SFT estimate is. Here the LSRPM estimates appear to be more reasonable than the CYK which here appears to generally underestimate the static formation temperature. Both methods used here give considerably higher estimates for the SFT at the loss zone around 4500 m than the Horner method though it is more disturbed by the cooling than the neighbouring points. Similarly, the temperature recovery at 4250 m can be disturbed by the neighbouring loss zone around 4200 m, especially the later data. The SFT is here estimated from minimum number of data points and for only a weeklong temperature recovery. Therefore, some uncertainty is in the estimates, but the estimates indicate that the bottom hole temperature (BHT) in the well is close to 500°C (Figure 9).

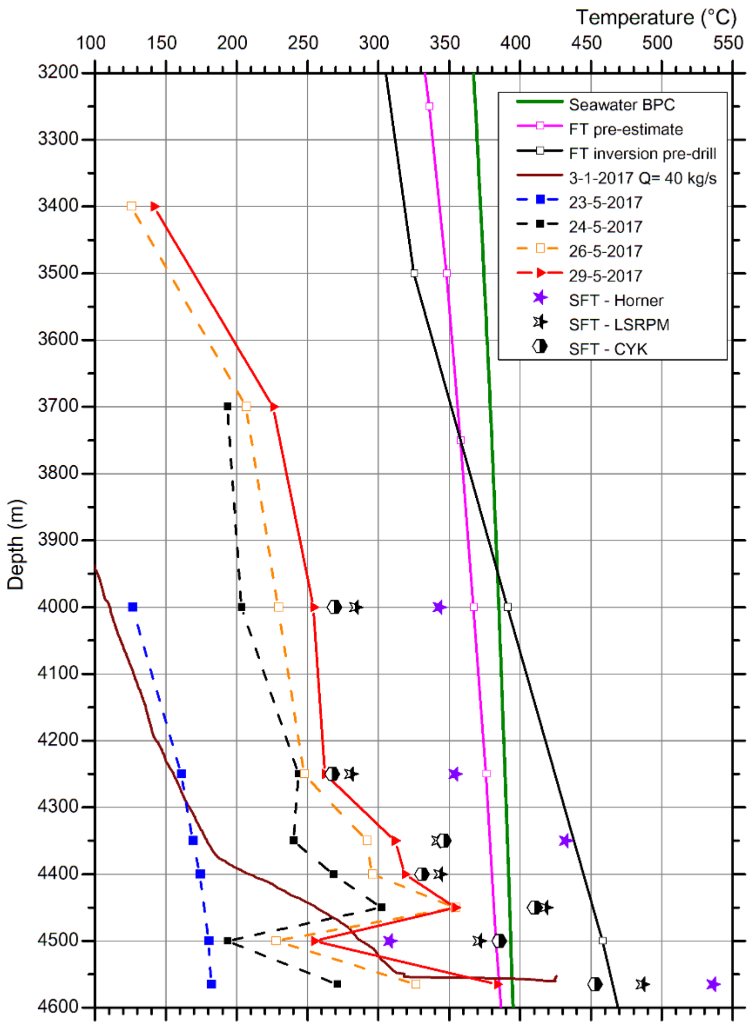

Figure 9. Temperature recovery measured at indicated depths and static temperature estimates (SFT) from three different models, Horner (min), LSRPM, CYK. Also shown are three pre-drill estimates for formation temperatures along with a measurement from January 2017 performed with 40 L/s injection and reaching supercritical conditions at bottom.

7. CONCLUSIONS

Injectivity at end of first stimulation stage was about 3.1 L/s per bar which is maybe reasonable for the deep formations but is lower than for production wells (4.5 L/s per bar and higher) in the upper part of the geothermal system at Reykjanes. At the end of stimulations, the injectivity is estimated around 2.8 L/s per bar or little lower, but then there is still considerable amount of fluid blocking material in the well which may still be active and limit the injectivity.

Warmup temperature measurements taken inside the stimulation string during a weeklong warmup period while rig pumps were used, indicate a loss zone around 4500 m that has accepted considerable amount of the water that was injected through the string. The warmup measurements further indicate that the cooling from the injection on the annulus and through the stimulation string was effective on the deepest part of the well. On the other hand, it is not quite clear how effective the fluid blocker was in view of the casing damages and that the stimulation string became stuck at those damages. Did the fluid blocking material build-up on the upper loss zones in the well or just in the annulus of the well around the casing damages? How effective was the over pressure obtained on the annulus in stimulating the well and then especially the deeper section of it? These are questions that is difficult to answer, especially as it is not possible (or worth the risk) to log the well below the casing damages. However, one can conclude that during the first stimulation stage mainly the upper most loss zones above 3400 m were stimulated. In the second stage some stimulation occurred in the deeper section of the well as indicated by the cooling around 4500 m and around 4200 m. How later injection affected the well is difficult to speculate due to lack of downhole loggings.

During the stimulation period from January 2017 to September 2018 about 0.854 million tons of water were injected to the well. Of this were about 0.669 million tons of fresh water and about 0.185 million tons mixture of hot condensate and brine injected in the last few weeks when the warmup of the well was started. The fresh water cooled the well and about 18% of it was pumped through the stimulation string to the deepest section of the well (~0.118 million tons). At least that amount of water effectively cooled the deepest section of the well and potentially created fracture openings in that section.

Two pressure profiles were measured during the latter part of the stimulation period, but they have depth limit at 2300 m due to the casing damages. However, the profile from February 2018 basically follows earlier profiles indicating a controlling pressure reference at about 3150 m as was the case at end of drilling and during initial stimulations (see Figure 1 for comparison). The profile also indicates that the well has not warmed much up at that time despite relatively low injection rate. Similarly, the profile from September 2018 appears to extrapolate to the same pressure reference but at that time the warmup of the well had started so the gradient of the profile has increased.

At end of the drilling operation and beginning of stimulation activity the pressure reference control or pivot point was determined to be at about 3150 m (3144 m TVD), but earlier like in the measurement from October 2016 the pivot point was determined at 3360 m (3343 m TVD). The well was then 3648 m deep. Both those pivot points lie on the extrapolated hydraulic gradient from the shallower exploited geothermal reservoir at Reykjanes. That indicates that there is a pressure communication from the shallower reservoir to much greater depths. The upward shift in the pivot point is likely best explained by that the fluid losses to the loss zone around 3150 m depth had increased, but several cement plugs had been set at that zone to minimize circulations losses there during drilling without much success. Also, that the first stage of stimulation mainly affected those upper most main loss zones.

However, one can speculate that as the well was drilled into the formations with supercritical conditions that there was a change in the pressure conditions and a shift in the gradient. Due to the high temperature in the supercritical zone and likely low density of the fluid the shift in the deep gradient would be to a lower pressure value. However, this possible small shift in the pivot point would indicate that this possible pressure difference is not much, likely only of the order of about 8 bar.

Interpretation of the short temperature recovery measured indicates that the temperature in the deepest part of the well is well over the boiling point curve and in the supercritical region. Near bottom the SFT estimate is around 500°C.

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