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Analysis of Circulation Tests and Well Connections at Utah FORGE

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ABSTRACT

Circulation tests were conducted to test the connectivity between the injection well 16A(78)-32 and the production well 16B(78)-32 at the Utah FORGE site in July 2023. The results show that there is a connection between these two wells. Around 7,750 bbl of water were injected during the circulation tests. The maximum injection rate varied from 5 to 7.5 bpm (barrels per minute) and the surface pressure was about 4,000 to 4,500 psi. There were both pressure response and fluid production from the production well, which demonstrated the connection. The production rate was in the order of 10 bph (barrel per hour), which is only 3% - 5% of the injection rate. The connection was built on the fracture network created during the hydraulic stimulations conducted at the toe of well 16A(78)-32 in April 2022. The injection pressure was above the minimum total principal in-situ stress, which suggested proppants would be needed in future treatments to maintain fracture conductivity. The shut-in pressure of later cycles is greater than the previous cycles due to the increased pore pressure. The data show that treatment pressure and system stiffness were reduced, the time of pressure response in the production well decreased, and conductivity was increased with additional injection cycles and continuous injection. The possible reasons are 1) thermal cooling effects, 2) likely, overcoming pinch points residual from previous injection, 3) reservoir recharge, and 4) water-rock interaction by continuous circulation and flowback.

1. INTRODUCTION

Utah FORGE (Frontier Observatory for Research in Geothermal Energy) is an Enhanced Geothermal System project supported by the U.S. Department of Energy. The drilling of injection well 16A(78)-32 was completed in December 2020. In April 2022, three stages of hydraulic stimulation were conducted at the toe of injection well 16A(78)-32 (McLennan et al., 2023). Production well 16B(78)-32 was drilled into the microseismic clouds from the stimulations in June 2023, and it is nominally 300 ft above the injection well (refer to Figure 1). Right after drilling the production well, circulation tests were conducted to test the connectivity between the injection well 16A(78)-32 and the production well 16B(78)-32 in July 2023.

This paper describes the circulation tests and analyzes the connectivity between the injection and production wells.

2. OVERVIEW OF CIRCULATION TESTS

The circulation testing implemented low-rate injection to interrogate the reservoir between the injection and the production wells, 16A(78)-32 and 16B(78)-32. More importantly, it was necessary to assess the degree of interconnection that had resulted from the previous fracturing campaign (April 2022) and to determine the partitioning of flow between the three frac stages previously pumped. Consequently, the circulation testing was designed to use low enough injection rates so that limited new hydraulic fracturing would be created.

Two circulation test series were conducted at the Utah FORGE site in July 2023. In each circulation series, the injection spanned two to three separate days. As shown in Figure 1, Circulation Test 1 was conducted before casing was installed in production well 16B(78)-32, and Circulation Test 2 was conducted after the casing had been run and cemented. For Circulation Test 1, the maximum pumping rate was 5 bpm and the injected volume was 3,300 bbl; for Circulation Test 2, the maximum pumping rate was 7.5 bpm and the injected volume was 4450 bbl. The pumping rate is low compared to that of the hydraulic stimulation in April 2022, which was between 35 and 50 bpm, depending on the stage.

3. CIRCULATION TESTS RESULTS AND ANALYSIS

3.1 Circulation Test 1

3.1.1 Injection pressure profile

Fluid was injected into well 16A(78)-32 using one pump truck. The surface treating pressure at 16A(78)-32 on Day 1 (July 4, 2023) is shown in Figure 2(a). The injection started at 0.5 bpm, was later increased to 2.5 bpm, and finally was increased to a maximum rate of 5 bpm. The single pumping unit could not achieve 5 bpm at the wellhead pressure encountered and a second (standby) unit was rigged up and brought online. Subsequently, the first pumping unit was shut down due to mechanical issues and the last part of the first day was carried out with a single pumping unit. The injection program on Day 2 (July 5, 2023) was to pump for 6 hours at a constant injection rate of 5 bpm.

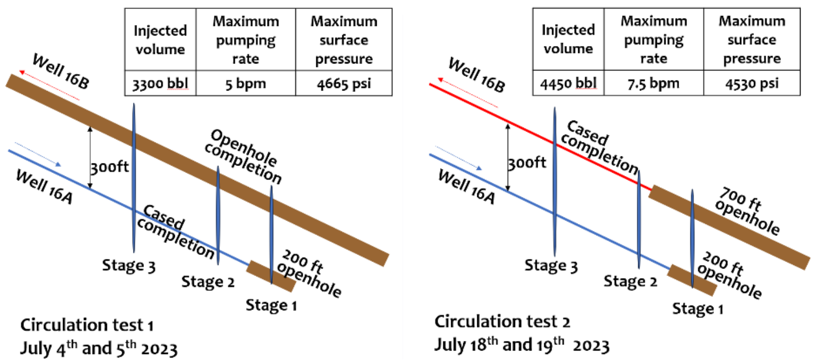
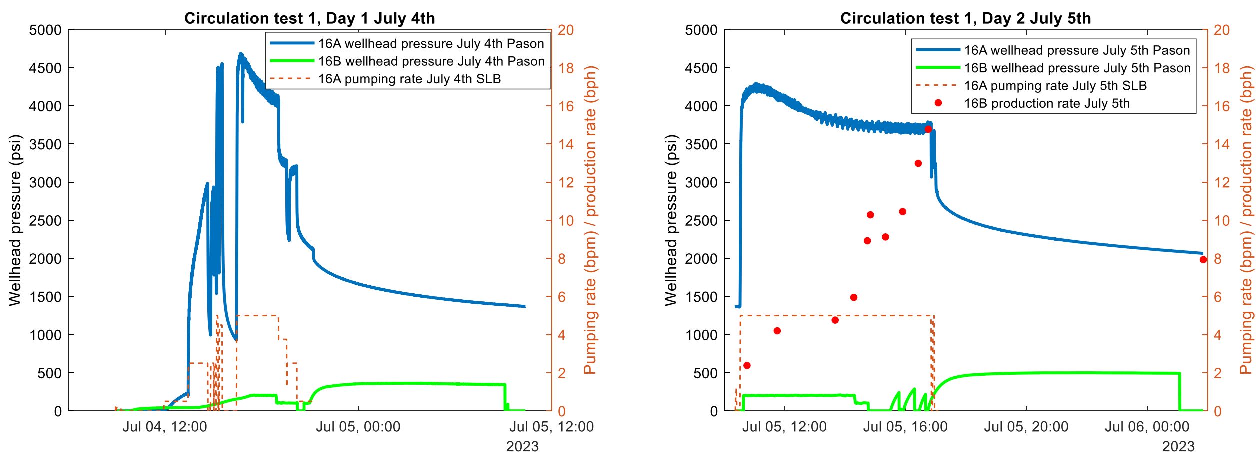


Figure 1: Sketch of the circulation tests. At left, the initial testing (Circulation Test 1) was done before the production casing was run and cemented. At right, the later injection testing (Circulation Test 2) was performed after running and cementing the casing, but with no perforation.



(a) **(b)**

Figure 2: Wellhead pressure, injection rate, and producing rate for Circulation Test 1

Notice several features:

1) Wellhead pressure did not build rapidly at 0.5 bpm. This is unlike the initial openhole DFIT run in early 2021 and a brief shear stimulation test (during Stage 1, 2022) which built pressure and opened rapidly. This is not unexpected because additional frac stages have been pumped since those treatments were pumped, and conductivity was enhanced near the well 16A(78)-32 wellbore.
2) There could have been some very limited fill-up of casing fluid volume at the start of pumping. The cause of the rapid pressure decline for some slug tests performed several days prior is uncertain since the well has held pressure since pumping terminated – indicating almost no reservoir permeability – as expected from the lack of drilling mud losses while drilling both wells. The slug test suggested composite permeability was enhanced near the wellbore of injection well 16A(78)-32, but for the far field, the reservoir permeability was still low. Once the reservoir near wellbore was recharged, the pressure will be held for a long time.
3) When the injection rate was increased to 5 bpm, the wellhead pressure built more rapidly and rolled over at about 4,486 psi. This pressure is well above the previously determined fracture gradient (0.75 psi/ft) considering a wellbore filled with water.

From the injection pressure profile of Circulation Test 1, we can see that there was fracture reopening or fracture propagation because there is pressure slope change and pressure decrease after the peak. Not only is the injection pressure greater than the fracturing pressure (the reopening pressure would correspond to 3,000 psi surface pressure without pipe friction), but also the maximum pressure for both Day 1 and Day 2 circulation is greater than that during the hydraulic stimulation Stage 1 in April 2022 at the same pumping rate, 5 bpm (refer to Figure 3 and Table 1). The well completion is different for these two situations: during the hydraulic stimulation Stage 1, only the openhole section took fluid; while for the circulation test, all the three stages took fluid. There could also be water-rock interaction on the fracture surface that makes the fracture more difficult to initiate after 15 months.

By comparing the pressure profile of Day 1 (July 4, 2023) and Day 2 (July 5, 2023) for Circulation Test 1, we find that the treatment pressure during the Day 2 (July 5, 2023) is lower than for Day 1 (July 4, 2023). That's because the fracture was already reinitiated or reopened (pinch points were overcome) on Day 1. Cooling might contribute to the lower maximum pressure in Day 2 as well. As cold water was injected, the induced thermal stress might have reduced the fracturing pressure (Perkins and Gonzalez, 1985). We also notice that the pressure after shut-in after pumping on Day 1 is lower than for Day 2. It is due to the elevated pore pressure, caused by the fluid dissipated into the natural fracture network during Day 1.

Table 1: Comparison between circulation test in 2023 and hydraulic stimulation in 2022.

Item	Circulation test 1 in July, 2023		Hydraulic stimulation Stage 1 in April, 2022
Maximum pressure at 5 bpm (psi)	Day 1 (July 4, 2023)	Day 2 (July 5, 2023)	4100
	4665	4277	
Completion status	Stage 1: openhole Stage 2: cased and perforation Stage 3: cased and perforation		Stage 1: openhole

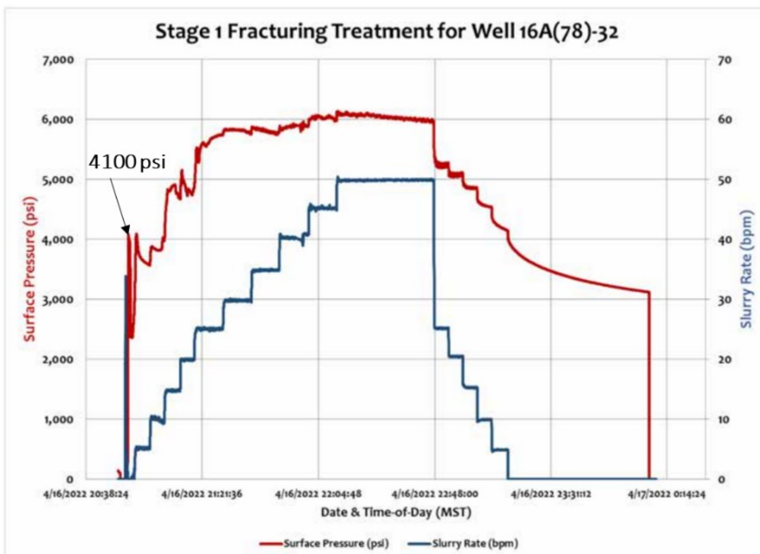


Figure 3. Hydraulic stimulation Stage 1 conducted in the openhole section of well 16A(78)-32 in April, 2022. Slickwater was pumped.

3.1.2 Communication between the injection well and the production well

Well 16B(78)-32 (refer to Figure 2) produced fluid and recorded a pressure responseFigure 2 during this first circulation tests. As shown in Figure 4, the slope of the injection pressure versus time curve changed at 1:25 pm on July 4, 2023. This means the reservoir stiffness was changed and fluid started to enter the previously created fracture system. After about 40 minutes, the pressure started to rise in production well 16B(78)-32. The wellhead pressure on well 16B(78)-32 built up slowly with the flow line closed (i.e., the well was shut-in at the surface and the throttling valve to the pit from the production well was closed). When the wellhead pressure in 16B(78)-32 reached 200 psi, the throttling valve in the flow line was opened to maintain 200 psi as back-pressure by flowing to the pit. Later during the pumping, the back pressure was reduced to 100 psi. After the injection stopped, both injection well 16A(78)-32 and production well 16B(78)-32 were shut in. The pressure in well 16B(78)-32 built up to 362 psi was maintained at around 360 psi thereafter by bleeding off periodically. On Day 2 (July 5, 2023) of Circulation Test 1, the wellhead pressure for 16B(78)-32 increased only 5 minutes after the pressure slope in injection well 16A(78)-32 changed, indicating a more substantial connection between the injection and the production wells. The wellhead pressure for well 16B(78)-32 was manually kept at 200 psi afterwards. After shut-in of injection well 16A(78)-32, the throttling valve on the flow line from well 16B(78)-32 was closed and the pressure built up to 500 psi and was maintained at 500 psi thereafter.

During Day 1 (July 4, 2023) of Circulation Test 1, there was flow from the production well to the pit, but it was below the lower threshold for the flow meters placed in the flow line from well 16B(78)-32 – per manufacturer, this is 1 bpm. During Day 2 of Circulation Test 1, flow measurements (refer to Figure 2) were made by timing flow into a five-gallon bucket. The producing rate from well 16B(78)-32 was about 10 bph (barrel per hour), which is 3%-5% of the injection rate.

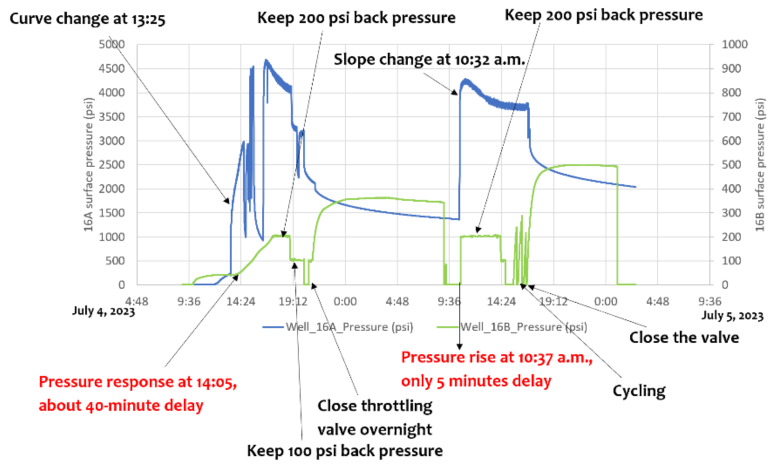


Figure 4: Wellhead pressure of injection well 16A(78)-32 and production well 16B(78)-32 during Circulation Test 1 (including both Day 1 and Day 2).

3.2 Circulation Test 2

3.2.1 Injection pressure profile

Circulation Test 2 was conducted after casing had been installed in the production well 16B(78)-32. Two pump trucks were hooked up to well 16A(78)-32. The treating pressure at the 16A(78)-32 wellhead on Day 1 (July 18, 2023) is shown in Figure 5(a).

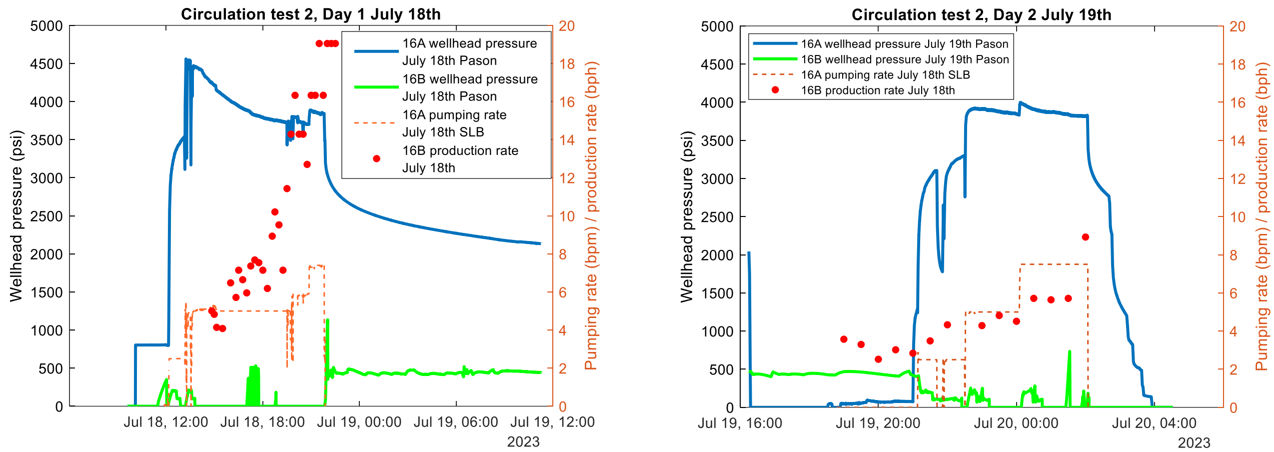
On Day 2 (July 19, 2023), a grease head was rigged up for pressure control while running the SLB HT PLT tool (sometimes referred to as PTS – pressure, temperature, spinner tool). There was a lubricator on location, but the available crane could not lift it. Consequently, it was necessary to flow Well 16A(78)-32 to the pit to relieve pressure before installing the grease head. Flowback started at about 4:15 p.m. on July 19, and lasted for about 5 hours. Injection started about 9:09 p.m. on July 19, 2023. The injection pressure and pumping rate, and the response of production well 16B(78)-32 for Day 2 (July 19/20, 2023) circulation are shown in Figure 5(b).

As listed in Table 2, the maximum pressure at a rate of 5 bpm on July 18, 2023 (Day 1 of Circulation Test 2) was larger than July 5, 2023 (Day 2 of Circulation Test 1), but smaller than July 4, 2023 (Day 1 of Circulation Test 1). This is expected because there was a 13-day shut-in between July 5, 2023 and July 18, 2023, the reservoir healed somehow (e.g. the cooling effect diminished) and the total stress increased due to "back pressure" by poroelastic effects related to residual fracturing pressure in secondary fracture networks. The ISIP also increased as more fluid was injected (refer to Table 2) due to increase of total stress due to photoelasticity effect. Similar effect was found during the injection test conducted at well 58-32 (Xing et al., 2020).

Not only was the maximum pressure on July 19, 2023 (Day 2 of Circulation Test 2) much smaller than on July 18, 2023 (Day 1 of Circulation Test 2), but also the treatment pressure stayed relatively constant. The injection pressure trend for July 18, 2023 (Day 1 of Circulation Test 2) is similar to that for Circulation Test 1, which showed pressure peak followed by a decrease in treating pressure of 300 to 500 psi during 1.5 hours of pumping at 5 bpm. However, the pressure profile on July 19, 2023 (Day 2 of Circulation Test 2) was relatively flat, only decreasing by 77 psi during 1.5 hours of pumping at 5 bpm. One of the reasons could have been the 5 hours of flowback from the injection well before the injection at Day 2 of Circulation Test 2. The flowback might have removed the substance at the fracture surface, which resulted in the increase of the conductivity between the two wells, especially the conductivity near the injection well 16A(78)-32. There are three possible reasons that contribute to the lower maximum pressure and flat pressure change for the July 19/20, 2023 injection: 1) pinch points were already overcome in by previous circulation cycles, 2) substance on fracture surface was removed during 5 hours flowback, 3) cooling effects.

Table 2: Comparative injection pressure profile between Circulation Test 1 and Circulation Test 2 in 2023.

Item	Circulation Test 1		Circulation Test 1	
	Day 1 (July 4, 2023)	Day 2 (July 5, 2023)	Day 1 (July 18, 2023)	Day 2 (July 19/20, 2023)
Maximum pressure at 5 bpm (psi)	4687	4277	4471	3910
ISIP (psi)	1961	3063	3258	3343
Pressure decrease after 1.5 hour of 5 bpm injection (psi)	464	323	325	77
Pressure after 8 hours of shut-in (psi)	1460	2090	2275	N/A
Injection pressure pattern	Peak and large decrease	Peak and large decrease	Peak and large decrease	Small change



(a) (b)

Figure 5: Wellhead pressure, injection rate, and producing rate for Circulation Test 2

The pressure in the injection well after 8 hours shut-in following the July 18, 2023 injection (Circulation Test 2) was larger than for after injection on Day 1 and Day 2 of Circulation Test 1. Again, this is likely due to elevated pore pressure caused by the fluid dissipated into the natural fracture/reservoir during the previous injection activities. It also indicates the reservoir is "tight", and the pressure was "held" for the 13 days of shut-in between Circulation Test 1 and Circulation Test 2.

3.2.2 Communication between injection well and production well

Evidence of communication between the production and injection well is provided by both the pressure response and fluid production during Circulation Test 2. The pressure response time (how long it took for a pressure change in the injector to be felt in the producer) gradually reduced as more fluid was injected (refer to Table 3). During Circulation Test 1, the fractures still needed to propagate or reopen/reinitiate – including charging secondary fractures that might not directly contribute to connectivity. Hence time is required to build the connection between injection well and production well. Pressure response is instantaneous in Circulation Test 2 because there was already a conductive connection (although the conductivity could be small) between the injection well and production well, created by hydraulic stimulation and fractures reopened by Circulation Test 1. The whole system was inflated in Circulation Test 1 and the fluid was not fully dissipated after 13 days of shut-in. Recall that the total volume pumped in the four days of sporadic circulation was 7,750 bbl and ~10,000 bbl were pumped during the 2022 stimulation campaign – fractures created in the three stage hydraulic fracturing campaign needed to be recharged. The pressure in the production well built up to 1,135 psi, occurred after the well was shut-in following pumping on Circulation Test 2, Day 1. This build-up pressure was accidental because the plan was to start flowing 16B(78)-32 to the pit once the pressure reached 500 psi.

The production rate attributed to Circulation Test 2 (flow into the production well) is similar to that for Circulation Test 1 (refer to Table 3). However, in Circulation Test 2, both Stage 2 and Stage 3 (2022 fracturing stages) were likely behind the casing in the production well, which means that only some of the fluid circulated through the fracture entered the production well 16B(78)-32. The "actual" production rate in Circulation Test 2 could be higher if the well had been perforated where Stage 2 and 3 fracture systems ideally intersection the wellbore.

Table 3: Comparison of wellbore communication between Circulation Test 1 and Circulation Test 2 in 2023.

Item	Circulation Test 1		Circulation Test 2	
	Day 1 (July 4, 2023)	Day 2 (July 5, 2023)	Day 1 (July 18, 2023)	Day 1 (July 19/20, 2023)
Pressure response time in production well	40 minutes	5 minutes	Instantaneous	Instantaneous
Producing rate	N/A	2 – 16 bph	4 – 19 bph	2 – 9 bph

3.3 Spinner Test Results

A production logging testing program was run on July 19/20, 2023. Pressure, temperature and spinner data were acquired at different rates and at different tool positions in Well 16A(78)-32. The spinner data for July 19/20, 2023 (Day 2 of Circulation Test 2) is summarized in Figure 6. This figure shows that Stage 1 and Stage 3 took most of the fluid while Stage 2 took little fluid.

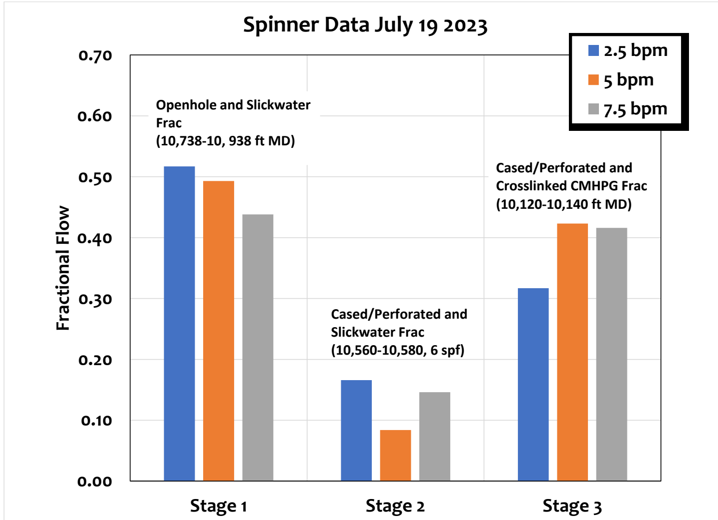


Figure 6. Final flow distribution – per SLB interpretation.

3.4 Stiffness Analysis

The system stiffness here refers to the ratio of pressure over injected volume before any damage (e.g., fracture initiation) is done to the reservoir (Raaen et al., 2001). In Figure 7, the undisturbed system stiffness is the slope of the initial linear section of the pressure vs. injected volume curve. Larger the system stiffness means the system has experienced less damage (i.e., fracture systems are closed or not connected), while smaller system stiffness means the system exhibits more "damage" to the continuum (e.g. more fractures). The reason for stiffness increased on July 5, 2023 compared to July 4, 2023 is not clear. The stiffness inferred for the July 18, 2023 injection is less than that for the July 4, 2023 and July 5, 2023 injections during Circulation Test 1 and this means that the fracture system interconnected in Circulation Test 1 was less significant. The stiffness for July 19, 2023 was substantially reduced suggesting that the fracture volume re-inflated on July 18, 2023 remained "active."

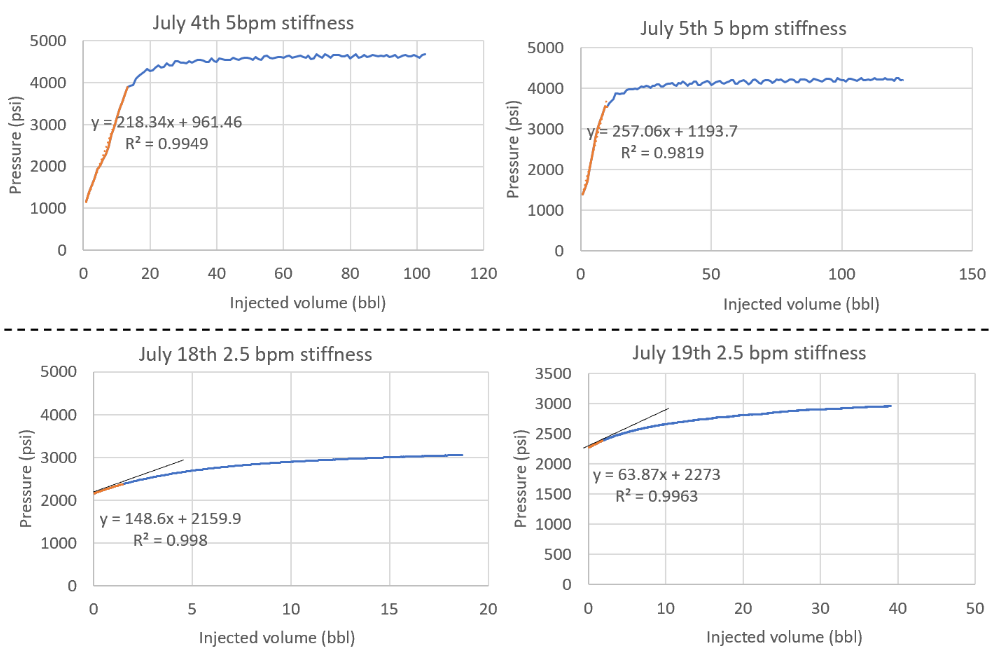


Figure 7. System stiffness for Circulation Test 1 and 2.

3.4 Material Balance of Fluid in the "Fracture System"

By taking into account the material balance of fluid in the "fracture system" between wells 16A and 16B, we can get a better understanding of the pressure response seen during the circulation tests in July 2023. The history of injected fluid volume into the reservoir since April 2022 is:

In April 2022 10,064 bbl of fluid were pumped into the reservoir during the 3 hydraulic fracturing stages. During flowback of each stage in order to set bridge plugs and perforate on drill pipe, 6,290 bbl of the injected fluid were pumped out. Since we don't suspect interaction of the 3 frac stages with each other in the reservoir, and because there is negligible leakoff of the fluid in any of the fracture systems created into the matrix of the granite reservoir, we can consider the process as effectively creating a storage tank within the reservoir. The original tank volume is 10,064 bbl and 6,290 bbl were removed during flowback, which leaves 3,774 bbl in the tank (37.5% full). It could be 3 separate tanks but from here we just assume it's a single tank.

For the circulation tests, on July 4, 2023, ~1,400 bbl of water were pumped into the formation. On July 5, 2023 water were pumped at 5 bpm for 6 hour 20 min for a total injected volume of ~1,900 bbl. On July 18, 2023, about 2,900 bbl of water were injected. PLT logging tools was installed into 16A(78)-32 on July 19, 2023. The crane did not have enough reach for the weight of the lubricator so we had to bleed pressure off of 16A(78)-32 by flowing to the pit so that we could install a grease-head for surface pressure control. It's not certain how much volume the well flowed back but with fluid temperature around 212°F the estimate is ~743 bbl. After that, An estimated 1,550 bbl of water were injected. After the injection, 16A(78)-32 had to been flowed back to the pit to reduce the wellhead pressure so that the PLT logging tools could be removed from the well. It's not known how much volume was flowed back to the pit.

The history of fluid volume change in the reservoir is:

1) Starting tank volume = 10,064 bbl
2) Volume flowed back from 16A after each stage and when retrieving the bridge plugs = 6,290 bbl
3) Current tank volume = 3,774 bbl (37.5% of capacity)
4) Circulation 1, Day 1 volume pumped into the tank = 1,400 bbl
5) Current tank volume = 5,174 bbl (51.4% of capacity)
6) Circulation 1, Day 2 volume pumped into the tank = 1,900 bbl
7) Current tank volume = 7,074 bbl (70.3% of capacity)
8) Circulation 2, Day 1 volume pumped into the tank = 2,900 bbl
9) Current tank volume = 9,974 bbl (99.1% of capacity)
10) Volume flowed back so that PLT logging tools could be run into 16A = 743 bbl
11) Current tank volume = 9,231 bbl (91.7% of capacity)
12) Circulation 2, Day 2 volume pumped into the tank = 1,550 bbl
13) Current tank volume = 10,781 bbl (107.1% of capacity)
14) Volume flowed back so that PLT logging tools could be removed from 16A(78)-32
15) Current tank volume = Probably <100% of capacity.

The volume of fluid that was flowed out of well 16B(78)-32 to the pit is not considered, however it is probably only on the order of 50 bbl. It should also be mentioned that microseismic activity was detected during Circulation Test 2, which indicated that additional hydraulic fracture creation and propagation was occurring in the Stage 3 microseismic cloud area from April 2022. This would mean that the fracture network "tank" volume was increasing during the circulation tests.

As a result of the material balance of fluid injected versus fluid flowed out it is clear that all of the fracture network could not have been re-filled. There was direct connection via a fracture network between wells 16A(78)-32 and 16B(78)-32, but there was minimal conductivity making it very difficult to circulate water at a higher rate. After the recharge rate is actually above 100%, the flow rate should begin to stabilize as long at the injection pressure is constant.

4. CONCLUSIONS

Circulation tests were conducted at the Utah FORGE site to assess the connectivity between the injection well and production well. There were two circulation test series: one was pumped before casing was installed in the production well, and the second was pumped after casing was installed. The maximum injection rate was 5 – 7.5 bpm, and the injected volume was 3,300 bbl for the Circulation Test 1 and 4,450 bbl for Circulation Test 2. The injection pressure exceeded the fracture reopening pressure during all of the circulation tests.

The results show that there is a connection between the injection well and the production well. Both a pressure response and fluid production from the production well were recorded. The production rate was about 10 bph, which is only 3% - 5% of the injection rate. The pressure in the production well can build readily, in one case rapidly increasing to over 1,100 psi before it was bled back. The production logging testing showed that both Stage 1 and Stage 3 took ~40% of the fluid, and Stage 2 took less than 20% of the fluid.

The reservoir pressure was increased due to the fluid injected into the reservoir and the increased reservoir pressure was sustained for a long time, which resulted in elevated pressure after shut-in of the two wells.

The measured connection demonstrated that there was a pathway created during the hydraulic stimulation in April 2022. However, because proppant was not used during that earlier stimulation (only a small amount of microproppant was used in Stage 3), the created fractures needed to be re-charged so that the conductivity could be restored 15 months after the 2022 stimulation. As a result, during the circulation tests, the injection pressure was above the fracturing pressure (minimum principal stress) to "reopen"/reinitiate the fractures. As more circulation cycles were conducted, 1) the injection pressure went down, 2) the pressure response time between the two wells decreased, 3) the system stiffness reduced, and 4) the conductivity increased. The possible reasons are 1) thermal cooling effect, 2) pinch points overcome by previous injection, 3) reservoir recharge, 4) and possibly water-rock interaction by circulation and flowback.

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