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Zonal Hydraulic Stimulation in the Salak Geothermal Field

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ABSTRACT

While hydraulic stimulation with zonal isolation is performed regularly in oil and gas reservoirs, it remains a rare practice in geothermal reservoir management. One of the main reasons for this hesitation, apart from extra cost and technical challenges, is a fear to potentially cement or case off sporadic feeding zones which consist of natural fractures in the reservoir. In this paper, we review a technical study conducted for the viability of such stimulation and the actual procedure successfully undertaken in the Salak reservoir during the 2012-2013 Drilling campaign.

Water injection management is part of the Salak geothermal reservoir optimization planning. In 2005, the Salak reservoir management team initiated the Salak Optimization Project to address this key issue. One of the strategic decisions was to move the brine injection out of the production area to the west of the Salak reservoir. Consequently, three injectors were drilled in the area, for which we encountered various but uneconomically low injectivity. All the three wells were hydraulically stimulated by injecting cold condensate water at high pressure for an extended period without any zonal isolation (bullhead stimulation) resulting in mixed outcomes.

In the 2012-2013 drilling campaign, a new method (i.e., zonal Isolation hydraulic stimulation) was proposed. We first constructed a conceptual geomechanical reservoir model to study benefits of zonal isolation. The study suggests that the zonal isolation stimulation will improve well injectivity and outperform bullhead stimulation. Thus we designed a well with a combined pre-perforated and blank 10-3/4" and 8-5/8" liner. The blank part was then cemented ~300ft high to create zonal isolation. Furthermore, main injection casing 13-3/8" was successfully installed in one string, which eliminated tie-back (common in geothermal well), improving its long term reliability. This combination of long string injection casing and zonal isolated liner would then allow RTTS to perform injection at specific zone.

Initial injection capacity was around 150 kph at 500 psi WHP. After the stimulation, the well injectivity was tested to be 600 kph at 500 psi WHP. This huge improvement has helped to eliminate the necessity of drilling another injection well.

1. INTRODUCTION

Currently all the brine water produced in the Salak field is re-injected into the reservoir. However, a study from the Salak Optimization Project (Ganefianto *et al.*, 2010) suggests that moving the brine water injection from the production area to outfield could add value because of development of steam cap in the reservoir. Following this study, the Brine Outfield Injection project, which plans to re-allocate 1,800 kph water in the west of the Salak producing reservoir (Figure. 1), has been commenced. Figure 1 shows the location where the three injectors were drilled. It is in the west of the Salak reservoir (Cianten region).

The first injector Awi 18-1 was drilled towards east of the wellpad. The initial injectivity of the well was 0.45 kph/psi and was not economical. From our own experiences (Passiki *et al*., 2010) and others (Grant *et al*., 2013) in injectivity enhancement over an extended period of injection, we have decided to apply high pressure, which supposedly exceeds the fracture opening, for an extended period of 10 months to obtain pronounced injectivity improvement. The response from the injector during this stimulation period is shown in Figure 2. As can be seen in Figure 2, the injectivity has increased significantly after the stimulatoin. The details of the Awi 18-1 injection stimulation and geomechanical modeling can be found in Yoshioka and Stimac 2010.

As depicted in Figure 1, Awi 18-2 was spudded at the same pad as Awi 18-1, and steered toward north. Based on our success in stimulating Awi 18-1 injector, a decision to conduct a similar hydraulic stimulation was made. Figure 3 shows the result of injection test back in 2012 (blue points), and actual operation data in June 2013 (red points).

As shown in Figure, Awi 18-2 stimulation was not as effective as the one for Awi 18-1. From a separated study on the regional stress and analysis in the image logs, the intermediate principal stress direction appears to be roughly NE-SW. Thus, Awi 18-2 probably does not intersect as many fractures as Awi 18-1, and for that reason, the injectivity has not been improved as much.

From these two different experiences, Awi 18-3 was decided to drill toward west from the Awi 18 pad parallel to Awi 18-1 considering the regional stress direction.

2. CONCEPTUAL GEOMECHANICAL STUDY FOR ZONAL ISOLATION

To investigate benefits of zonal isolation as a new stimulation technique for possible completion strategy, a conceptual geomechanics model was built to compare subsequent injectivity changes from both bullhead and isolated injection scenarios and assess the additional value of having zonal isolation. A conceptual model is a simple representative of injector in the Salak field under naturally fractured formation and some fault system.

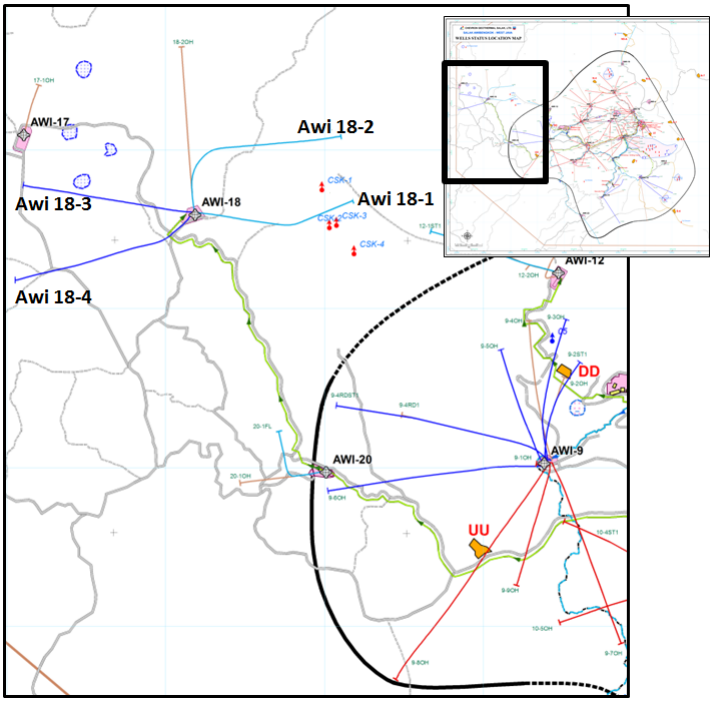


Figure 1: The Salak main reservoir is in the center and the Cianten region is in the west where three injectors (Awi 18-1, 18-2, and 18-3) were drilled.

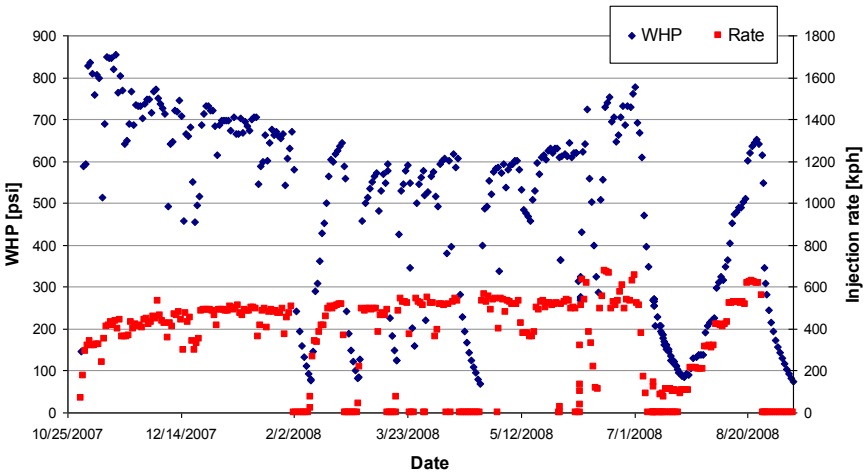


Figure 2: The long term high pressure stimulation result from Awi 18-1. Blue markers represent the well head pressures and red markers are the injection rates in the time period from October 2007 to August 2008. From October 2007 to February 2008, the well head pressures notably decrease while the injection rates increase indicating significant injectivity improvement

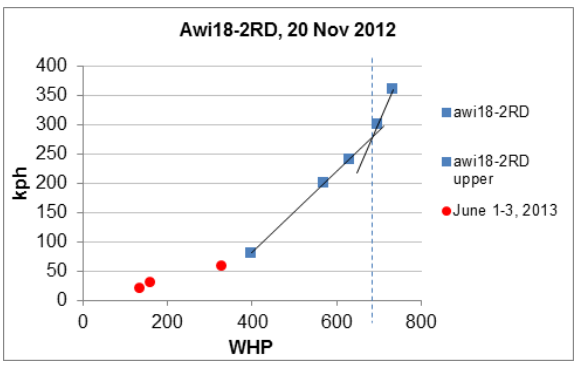
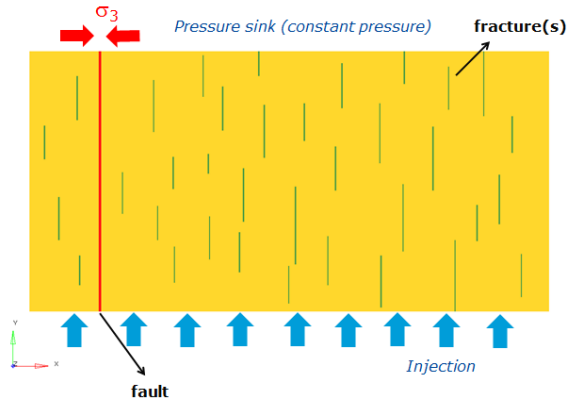


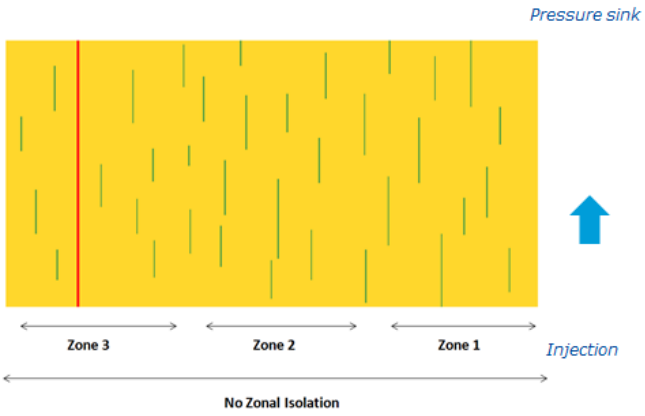
Figure 3: Awi 18-2 stimulation.

2.1 Conceptual model settings

Though the conceptual settings resemble the situation typically encountered by injectors, many of the idealized conditions are assumed (Figure 4). At one end we have a line source that represents a deviated injector and an open system that acts as a pressure sink (or constant pressure) is placed at the other end of the model. The reason for this constant pressure boundary is based on our experiences from Awi 18-1 injector. After the extended period of stimulation, pressure transient analyses indicate a nominal increase in the reservoir pressure despite the millions of barrels of water injection. Therefore, our current understanding of the west Salak formation is that there exists some sort of an open conductive system. However, as fractures are sporadic in general in the area, injectors need to be successfully stimulated to create new fractures or extend the existing ones to establish a connection to this open system. Further discussion about this open system or whether this is the Salak main reservoir or not is beyond the scope of this paper, and will be saved for another occasion. All the fractures are assumed to be optimally oriented to the minimum principal stress (E-W) with randomly distribution and length.



(a)



(b)

Figure 4: Schematic of the conceptual geomechanics model for zonal isolation benefit study. (a) One large fault intersects the injector and provides a connected path to the pressure sink, and optimally oriented fractures are randomly distributed in the orthogonal direction to the minimum principal stress with random length. (b) When zonal isolation is considered, injection will be isolated into three zones. Each zone has different characteristics in terms of fracture/fault intersection and connectivity to the pressure sink.

Fracture and fault are considered to have contrasted hydraulic and mechanical properties. Fractures and fault have the porosity of 0.3 and the permeability of 1000 md whereas matrix permeability is 0.001 md with the porosity of 0.05. As for the mechanical properties, fractures and fault have the elastic modulus of 8,000,000 psi and poisson's ratio of 0.25 while the matrix's elastic modulus and poisson's ratio are 1,000,000 psi and 0.25 respectively. The thermal expansivity of the both fracture and matrix formation is considered 1e-5 $1/^{o}F$.

As depicted in Figure 4b, an injector with zonal isolation is completed in the following three zones:

1) In the zone 1, a well intersects a fracture but has no continuous connection to the pressure sink. Therefore, a small injectivity is expected in this zone.
2) A completion in the zone 2 has no immediate intersection with any fractures. Thus, unless fractures get initiated at the injector and connected to the existing ones, minimum injectivity is anticipated.
3) A completion interval in the zone 3 has an established connection to the pressure sink through a fault. Therefore this zone should behave as a big thief zone.
4) A geomechanical model used in the study is a fully coupled geomechanics-reservoir code with capabilities of poro- and thermo-elasticity with optional non-associative plasticity. For the plasticity model in this study, we considered a Drucker-Prager power hardening model whose yielding surface given as:

$$F = \sqrt{J_2} + \alpha I_1 - \kappa\left(\varepsilon^p\right)^m - \Gamma \quad (1)$$

where I_1 is the first invariant and J_2 is the second invariant of the deviatoric stress, α, κ, and Γ are non-negative scalar parameters and ε^p is the plastic strain. Once the rock yields, the permeability is assumed to enhance according to the plastic strain. We considered an exponential permeability evolution as a function of the plastic strain as shown in Figure 5.

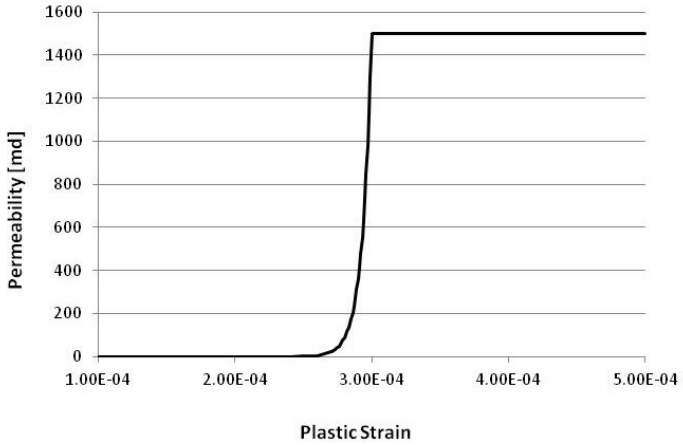


Figure 5: Permeability as a function of plastic strain.

The enhanced permeability is assumed to increase up to 1500 md, which is 50% higher than the initial fracture/fault permeability. Also note that this permeability change is applied to the whole permeability tensor. Therefore, any directionality of the rock failure or fracturing is neglected, and probably in more realistic condition, both mechanical and hydraulical changes might be more localized than predicted by this model for that reason.

2.2 Conceptual model results

We considered two injection scenarios. First scenario is a case of bullhead injection without zonal isolation capability for 90 days. The second scenario considers zonal isolation, and each of the three zones receives 30 days of injection totaling 90 days of injection. For the both scenarios, the injection is performed at a constant pressure which exceeds the initial minimum principal stress by 20%. Figure 6 shows the enhancement of the permeability after 30 days of injection. Figure 6a shows the enhanced permeability profile after 30 days of injection for the both bullhead and zonal isolation scenarios. The bullhead injection as expected, the majority of the fluid was injected into the fault (Zone 3), and the permeability enhancement is much more pronounced along the fault. However, there is some amount of stimulation in Zone 1. On the other hand, the case with zonal isolation, only stimulated Zone 1, and was able to establish a connection to the pressure sink. The temperature profile in Figure 6b confirms this connectivity.

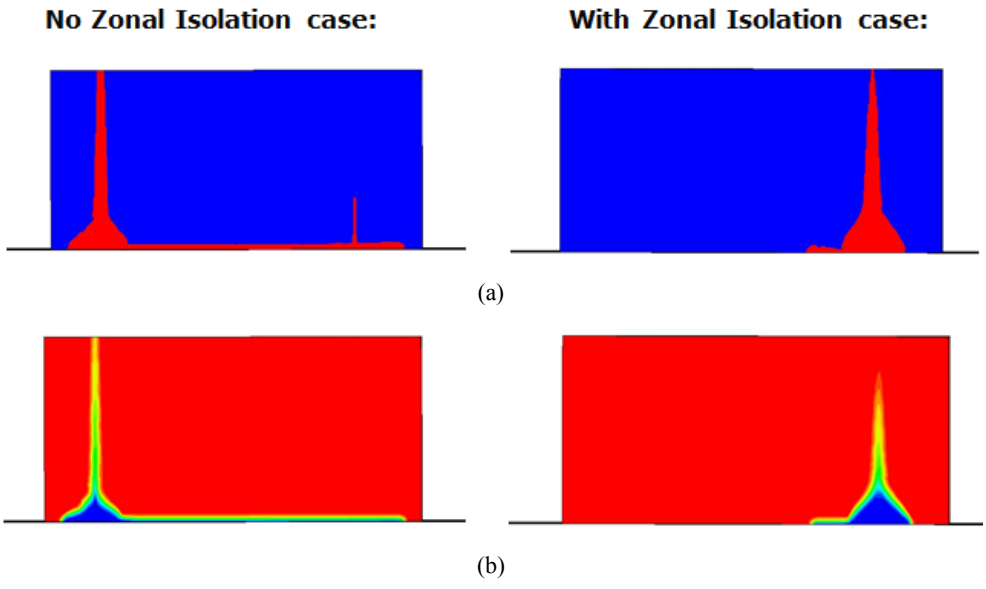


Figure 6: (a) Permeability enhancement profile, and (b) temperature profile after 30 days of injection for bullhead injection and injection with zonal isolation. Permeability enhancement is concentrated along the fault for the bullhead scenario while the zonal isolation scenario successfully established a connection to the pressure sink. The temperature profiles also show the distribution of injected water.

For the bullhead injection scenario, the injection continues for another 30 days with the exact same condition while we shut off Zone 1 and isolate Zone 2 for the zonal isolation scenario. Figure 7 shows enhanced permeability and temperature profiles after 60 days of injection. More volume was stimulated for the bullhead injection scenario, but still the stimulation is concentrated along the fault, and a small stimulated volume in Zone 1 remains small without significant improvement. This is because the permeability in Zone 3 is so high that most of the injection is taken in by this zone, and not enough pressure can be built up in other zones. This is also observed in the temperature profile. The case with zonal isolation shows some small volume of stimulation, but it was not successful in extending the rock failure to the existing fractures. This result indicates that an isolated zone without any fracture intersection may require a massive pump and/or perforation to initiate fractures, or an extended period of injection to have connection with the existing fractures.

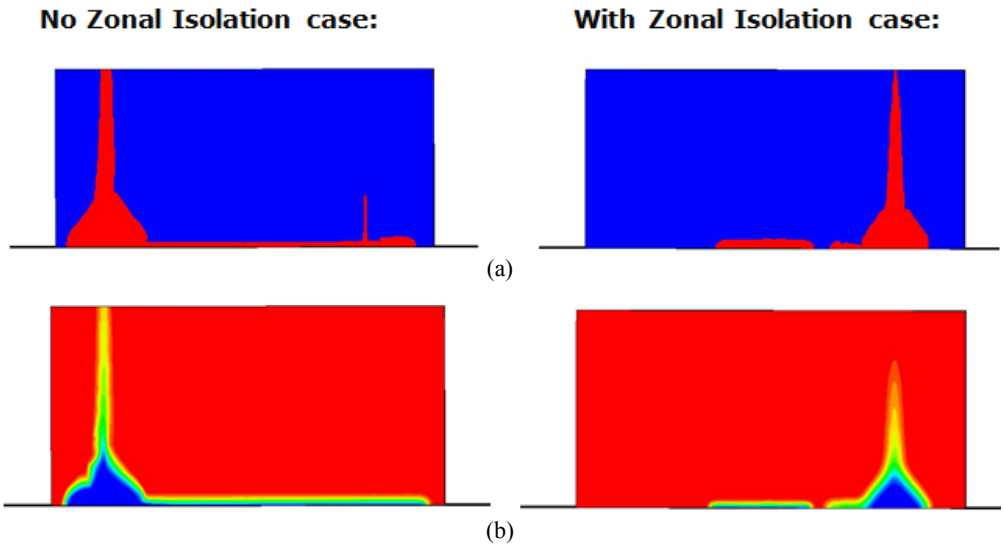


Figure 7: (a) Permeability enhancement profile, and (b) temperature profile after 30 days of injection for bullhead injection and injection with zonal isolation. Permeability enhancement is still concentrated along the fault for the bullhead scenario. Only Zone 2 received injection in this period for the zonal isolation scenario, but the stimulation in this zone was not successful. Although a small amount of failure was observed, it is not enough to connect existing fractures.

While the bullhead injection went on for another 30 days, injection for the zonal isolation case was shifted from Zone 2 to Zone 1 where the injector intersect with the fault. As expected, stimulation of Zone 1 had no problem and the well was able to establish a connection to the pressure sink. For the bullhead injection case, although we can observer further increase in the stimulated volume along the fault, stimulation in Zone 3 did not improve after all. Without zonal isolation, it is difficult to divert injection from already established thief zone and stimulate other zones. However, it is important to note that this concentration of stimulation only intensifies with time leaving other zones un-stimulated. From the two permeability enhancement profiles in Figure 8a, we can easily conclude that zonal isolation will provide more evenly distributed stimulated volume over the entire interval.

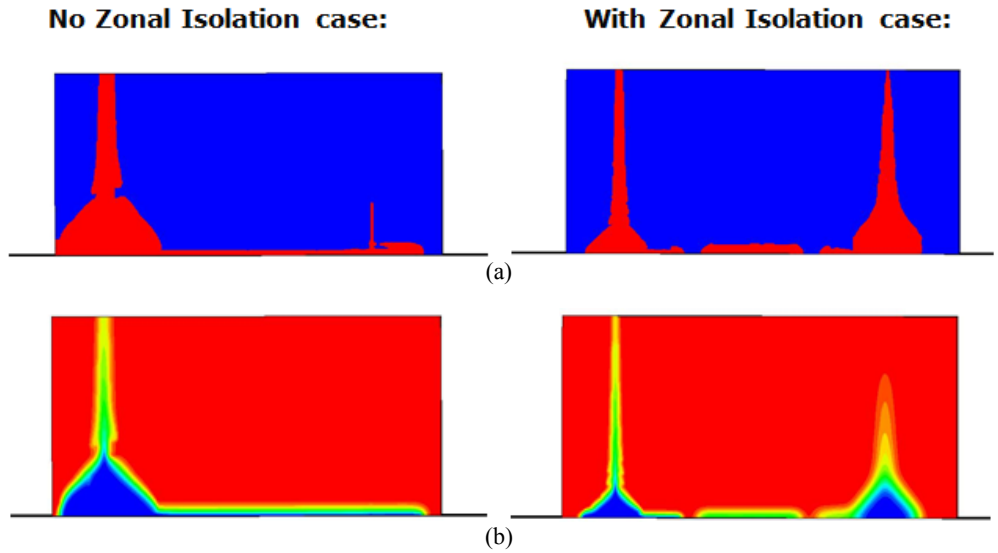


Figure 8: (a) Permeability enhancement profile, and (b) temperature profile after 30 days of injection for bullhead injection and injection with zonal isolation. With bullhead injection, almost no change in stimulated volume has observed except for Zone 1 with the fault. For the zonal isolation scenario, the stimulation this time took place in Zone 1 and successfully established a connection to the pressure sink.

3. STIMULATION WITH ZONAL ISOLATION

The results are analyzed with a modified Hall plot (Izgec and Kabir, 2009). As opposed to generating a single curve in conventional Hall plot, a modified Hall plot also utilizes derivative of the Hall integral and compare these contrasting two curves to obtain further information about the injectivity. When the derivative goes below the Hall integral curve, it is indicative of injectivity improvement (fracturing) and if the derivative rides above the integral, it implies worsening of injectivity such as plugging or scaling. These two curves trace the same path in matrix-dominated flow regime. The Hall integral can be obtained by integrating the pressure difference between the downhole and reservoir with respect to time and the derivative curve can be obtained numerically by

$$D_{HI} = \frac{\int\left(p_{wf} - p_e\right)^{n+1} dt - \int\left(p_{wf} - p_e\right)^{n} dt}{\ln(W_i)^{n+1} - \ln(W_i)^{n}} \tag{2}$$

where p_{wf} and p_e are the downhole and reservoir pressure respectively, and W_i is the cumulative injection.

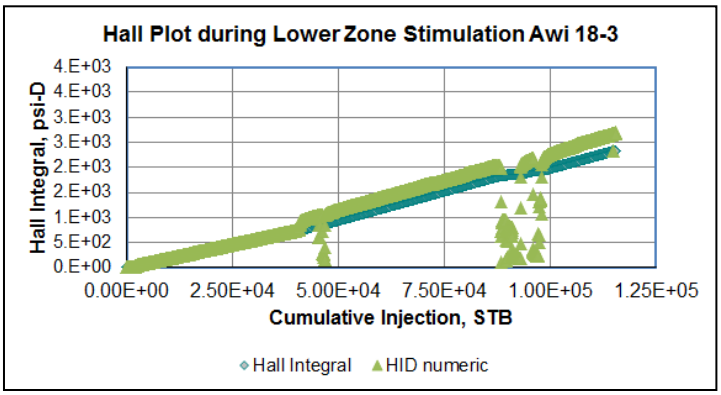


Figure 9: Modified Hall Plot during Lower Zone Stimulation

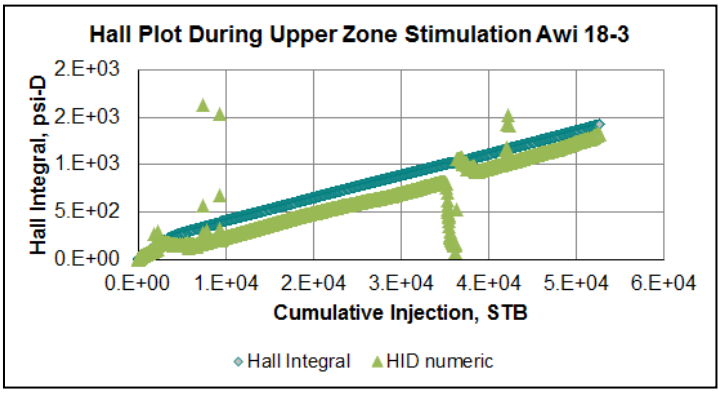


Figure 10: Modified Hall Plot during Upper Zone Stimulation

The stimulation in the upper zone experienced some plugging when the cumulative injection reaching about 0.05 MMSTB, as indicated by the derivative of the Hall integral which rides above the Hall integral (Figure 9). No fracturing happened in this zone. However, the upper zone stimulation, improved early during injection, as indicated by the derivative going down below the Hall integral early in the plot (Figure 10). These different results also showed that the isolation method worked as intended. The same plot over actual injection operation data (after stimulation), showed that significant fracing happened after about 1.5 MMSTB water injection. The bending Hall integral indicates this improvement, more clearly showed by the decreasing derivative (Figure 11). The reason for the success in upper zone and not in lower zone is beyond the scope of this paper, and will be saved for other occasion.

4. CONCLUSIONS

Conclusions drawn from the conceptual section are:

- A simple conceptual model was run in 2D with the aim of understanding benefits of having zonal isolation for injector.
- Three different configurations were considered in each of isolated zone, which are a zone with isolated fracture(s), a zone with no connection with fractures, and a zone with a fault that connects to an open system.
- While bullhead injection dominantly stimulates a zone with a fault, injection with zonal isolation is able to stimulate all the zones with fractures or faults.

- Zonal isolation does not guarantee all the zones will be stimulated. If a zone has no intersection with existing fractures, it may require to apply massive force (e.g. perforations or high pressure) and/or an extended period to gain initial access to the formation.

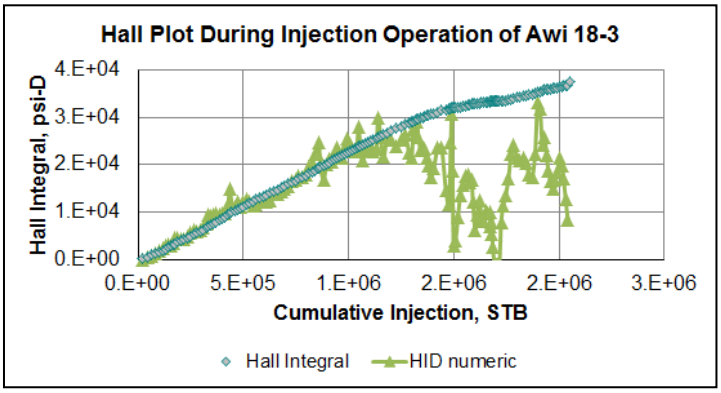


Figure 11: Modified Hall Plot during Injection Operation

Conclusions drawn from the zonal stimulation results are:

- The completion type used in the zonal stimulation in Awi18-3 worked as expected, able to isolate the zone of interest for each stimulation.
- As drawn from the conceptual model conclusion, the zonal isolation does not guarantee an improvement in injectivity. This is shown by the different results in the upper zone and the lower zone.
- The significant improvement shown only after actual injection operation in place, tells us that large injection volume and injection period plays an important role in stimulating the reservoir.
- While the zonal stimulation successfully targeting zone of interest, other factors such as initial fractures connectivity condition, or a longer period (larger water volume) are needed for the successful stimulation for each zone.

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