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Application of Hydraulic Stimulation to Improve Well Injectivity

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ABSTRACT

It is recognized that Salak reservoir performance would be improved through moving injection from current, infield locations, to outfield locations. During the last two drilling campaigns, several injector wells have been drilled outside of the proven reservoir boundary to replace existing infield injectors. Drilling wells outside of the known reservoir has always been challenging. A number of newly drilled wells have low permeability which limits their injection capacity due to poor connectivity to the large fracture network. Hydraulic stimulation on one of those wells had been applied and successfully improved injectivity. This paper describes the best practices applied during planning, designing and operating the hydraulic stimulation as well as technique to interpret surveillance data collected during stimulation.

1. INTRODUCTION

The Salak geothermal field has been producing the steam required for 110-377 MW of power generation for 16 years, with approximately 14,000 to 16,000 kilo-pound per hour (kph) brine injected in the proximity of the production area during this time. The initial strategy was to inject produced brine in close proximity to producers (**Figure 1**). About 70% of the produced brine is currently injected at Awi 9 location at west part of reservoir and the remaining is injected at proximal southeast area of the field (Awi 14 and 15 locations). Formulating injection strategies has proven to be the most difficult aspect of Salak field management. Monitoring programs such as tracer test, chemical monitoring, micro-earthquake monitoring and PTS (pressure temperature spinner) surveys have been carried out throughout the field development and production. It is recognized that breakthrough of cool injected fluid would eventually occur, and therefore realignment of injection strategy is necessary to optimize heat recovery.

The injection realignment program would include (**Figure 2**):

- Moving all infield condensate injection to outside of main reservoir
- Moving 3000 – 3500 kph of brine injection from Awi 9 location to southeast margin of the field (proximal southeast)
- Moving 2000 – 3000 kph of brine injection from Awi 9 location to outside of main reservoir

Awi 18 at Cianten caldera, located at west of the main reservoir, has been selected as place for outfield brine injection. In the last two drilling campaigns, four wells have been constructed at Awi 18 pad: Awi 18-1, 18-2, 18-3 and 18-4 to as part of system development for 2000 – 3000 kph of outfield brine injection. Based upon completion test, the injectivity of three wells drilled at Awi 18 were found to be too low for commercial injector.

Geothermal reservoir boundaries are somewhat vague. Therefore, new wells drilled in the region of reservoir boundary often encounter low or even zero permeability formations and need to be stimulated to provide adequate rates. Drilling record and completion tests suggested that those three wells had not suffered near-wellbore formation damage. Low injectivity of the wells is mainly due to naturally poor connectivity to the large natural fracture network. Therefore, hydraulic stimulation is selected to be applied to improve wells injectivity instead of other stimulation technique (Pasikki et al., 2010).

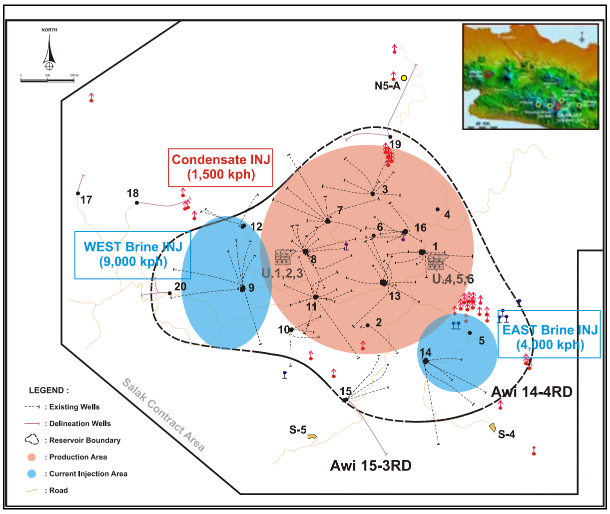

Figure 1: Map of Salak well field with re-injection areas (blue) located in the vicinity of the production area (red), in the periphery of the proven reservoir.

2. DEVELOPMENT OF AWI 18-1 WELL

2.1 Awi 18-1 Background

Awi 18-1 is the first well drilled at Awi 18 pad. Completion test in Nov 2006 found that the injectivity was very low. **Figure 3** shows the initial injectivity index of Awi 18-1 well was 0.45 kph/psi. The result from initial injectivity test in **Figure 3** also indicated that the well could take larger volume of water when injected with higher pressure (above 650 psi of wellhead pressure).

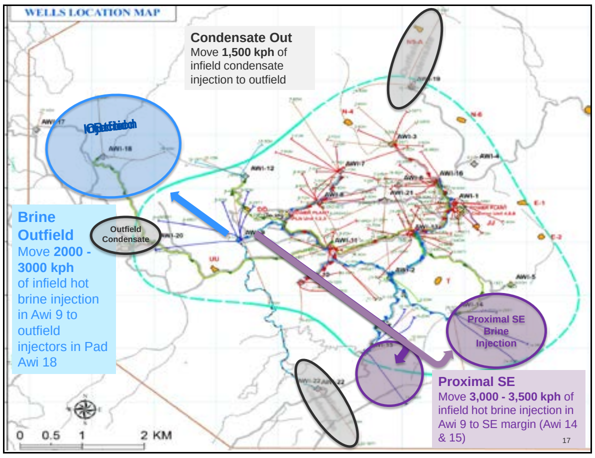

Figure 2: Map of Salak well field with planned injection realignment program

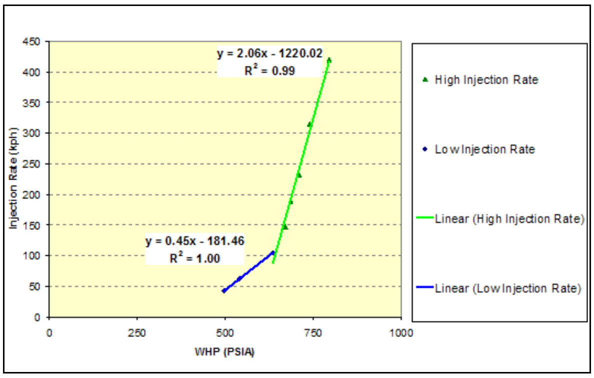

Figure 3: Injectivity test of Awi 18-1 well conducted in November 2006.

The injectivity index (II) is defined as

$$II = \frac{q_{inj}}{p_{wf} - p_r} = \frac{q_{inj}}{p_{wh} + \Delta p_h - \Delta p_f - p_r} \qquad (1)$$

where q_{inj} is the injection rate, and p_{wf}, p_{wh}, and p_r are the pressure at the bottomhole, wellhead, and reservoir respectively. Δp_h and Δp_f are the hydrostatic and frictional pressure loss. Kinetic pressure loss in the pipe is generally negligible. Rearranging **Eq. 1** gives

$$q_{inj} = II\left(p_{wh} + \Delta p_h - \Delta p_f - p_r\right) \qquad (2)$$

Therefore, the injectivity index can be computed from the slope of the injection rate plot against wellhead pressure assuming that *II* is constant with the injection rate and frictional pressure loss is not significant. The formation parting or the fracture extension/propagation pressure can be found at the point where the injection rate curve changes its slope (Nolte, 1988; Singh and Agarwal, 1990). Based on this curve, the interpreted fracture opening pressure at Awi 18-1 is 650 psia on the wellhead.

2.2 Hydraulic Stimulation at Awi 18-1

Based on completion test, the well can only take 50 kph of fluid at attainable operating wellhead pressure of 500 psi. This is far below the requirement of injection realignment program for 2000 – 3000 kph of outfield brine injection capacity. Given the needs to increase injection capacity, the main hydraulic stimulation was carried out. The stimulation program started on Oct 31, 2007 using three parallel (triplex) pumps with capability to pump up to 26 bpm (543 kph) at discharge pressure of 1000 psi. During stimulation, condensate water from the power plant with temperature of 80 – 100 ^{o}F was pumped and bullheaded into the wellhead. Close microseismic monitoring was also carried out throughout stimulation period.

Overall hydraulic stimulation process at Awi 18-1 well can be divided into two segments. For the first eight months, stimulation was done using three parallel pumps. We can observe that the WHP decreased significantly from the start of stimulation. At the same time, the injection rate shows an increasing trend. Both the decline of WHP and rise in injection rate are greater in the earlier period. After three months of stimulation the well injection capacity had significantly increased from 300 kph at 850 psi of WHP to 450 kph at significantly lower WHP of 600 psi. This is consistent with the microseismic observation wherein increased micro earthquake (MEQ) event occurred (magenta chart on **Figure 4**) within the first three months of stimulation. Increasing MEQ event during injection could mean that existing fractures start to slip and for the low permeability well this could also correspond with stimulation of the fracture system and hence improved well injectivity. As the well injectivity improved, the three available pumps can no longer attain the initial fracture opening pressure (650 psi pressure at the wellhead). As a result, well injectivity become steady after 3 months as indicated by steady WHP and the absence of MEQ event.

Considering halted improvement from continuous water injection, other alternative of hydraulic stimulation was evaluated. A conceptual modeling study (Yoshioka *et al.*, 2008) suggested that cycling pressure would improve injectivity. Therefore, a cycling-pressure type of injection stimulation was applied from March 14 to April 14. At the beginning of this cycling operation, the well was put under 25 bpm (525 kph) of condensate water injection for 5 days and then put under shut in condition for 5 days. The cycle period was gradually decreased by 1 day on subsequent cycles until a daily pressure cycle was attained.

During the first segment of hydraulic stimulation, three pressure fall-off tests were conducted. Our objective from these pressure fall-off tests is to evaluate the temporal stimulation results after applying both continuous injections and cycling-pressure stimulation. Therefore, we only focus on the estimation of *kh* and skin factor and leave out the discussion of the later period. We also conducted the fourth pressure fall off test at the end of overall stimulation program.

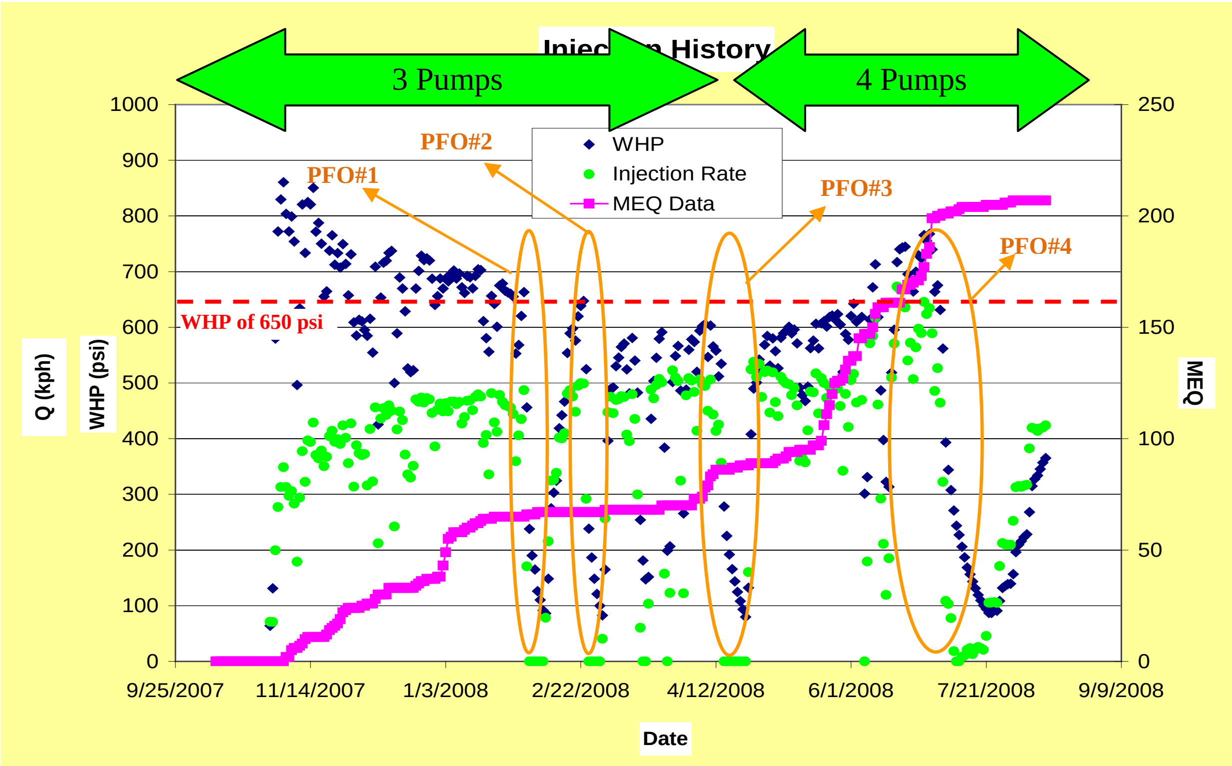

Figure 4: Injection and microseismic history during hydraulic stimulation at Awi 18-1 well

All the fall-off test results are plotted in log-log scale along with its derivative curve (**Figure 5)** using commercial pressure transient analysis software, *Saphir* (2007). The fall-off results show the characteristics of hydraulically fractured or highly stimulated wells, which are typically seen in geothermal wells (Horne, 1995). From the figure, we can notice two major features of the series of fall-off tests. Firstly, every test has experienced radial flow period followed by linear flow (zone 2 in **Figure 5**). In all the tests, the slopes of the later linear flow period are nearly ¼ or slightly less. This could be indicative of parallel sealing faults. Or it could be interpreted as a composite reservoir with different fractal dimension, which commonly occurs in fractured porous media (Acuna *et al.*, 1995). The second finding from this comparison would be the evolution of *kh* values in infinite radial acting region as suggested by a downward arrow in **Figure 5.** We can see that the flat line of the derivative curve does go down with time, which implies the higher *kh* values in the later tests.

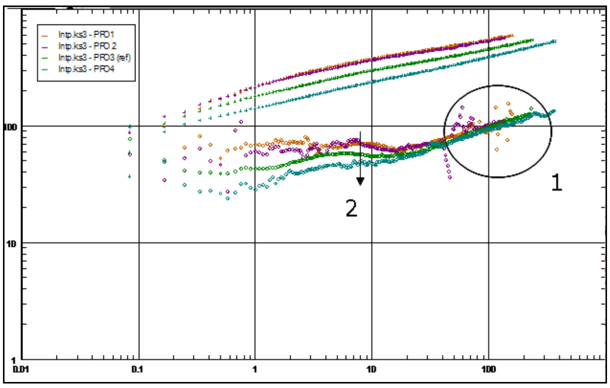

Figure 5: Plots of dp and dp' [psi] vs dt [hr] from PFO tests at Awi 18-1

Table-1 shows the summary of interpreted kh and skin from those PFO tests. From the first fall-off test, *kh* and skin are estimated as 6320 md-ft and -2.96 respectively and the estimates from the second test are 6180 md-ft and -3.01. This is an insignificant change. The second test was conducted 15 days after the first one. The third test, which was conducted 43 days after the second test, provides *kh* and skin estimates 8280 md-ft and -3.27 respectively. This is a significant improvement since the second test. Between the second and third fall-off test, we have conducted huff and puff injection. In addition, we have observed on average a lower wellhead pressure (~580 psi) than before the first and second tests (~660 psi).

Table 1 Summary of *kh* and skin estimation.

	Date	kh [md-ft]	Skin
PFO 1	Feb 2 - 9	6320	-2.96
PFO 2	Feb 24 - Mar 1	6180	-3.01
PFO 3	Apr 14 - 24	8280	-3.27
PFO 4	Aug 26 - Sep 11	8480	-3.73

With improved injectivity, the maximum capacity of the installed triplex pump cannot attain wellhead pressure higher than the initial fracture opening pressure (650 psi on the wellhead as shown on **Figure 4**). The WHP under maximum pumping rate (25 BPM) after the third PFO test was stabilized at around 600 psi. On the second segment of stimulation program, an additional pump was installed (on June 7, 2008) to increase pumping performance. With this additional pump, a continuous injection stimulation with higher pump rate and higher pressure (>700 psi WHP and 30 BPM rate) was conducted for a month followed by a step-up injectivity (II) test. At the end of stimulation program, several series of pressure-cycle operation were done. Unlike previous one, this pressure cyle operation applied 5 hours of pumping and 24 hours of shutting in. the well. The overall program was ended with the fourth fall-off test for 15 days. The *kh* and skin from the fourth fall-off test can be interpreted as 8480 md-ft and -3.73 respectively. It is not as significant change from the one previously observed but is still a sound improvement.

2.3 Hall Plot Application for Monitoring Awi 18-1 Performance

Hall's method is a simple tool used to evaluate performance of water injection wells. The main concept is to plot a cumulative pressure time product against the cumulative volume of water that has been injected. The plot gives an indication of the injection behavior; a change in injectivity appears as a change in the slope of this plot. A Hall plot can be constructed by plotting integral of pressure difference between bottomhole and reservoir on the vertical axis and cumulative injection volume on the horizontal axis. In pseudo steady state radial flow, we can write

$$q_{inj} = \frac{2\pi kh\left(p_{wf} - \overline{p}\right)}{B_w \mu \left(\ln \dfrac{0.472 r_e}{r_w} + s\right)} \qquad (3)$$

where $\overline{p}$ is the average pressure of the reservoir and B_w is the formation volume factor of the water. Taking an integral on both sides, we have

$$\int_0^t q_{inj}\,dt = \frac{2\pi kh}{B_w \mu \left(\ln \dfrac{0.472 r_e}{r_w} + s\right)} \int_0^t \left(p_{wf} - \overline{p}\right) dt = M \int_0^t \left(p_{wf} - \overline{p}\right) dt \qquad (4)$$

A plot of the cumulative injection and the integral of pressure will give a straight line with a slope of M^{-1} if skin factor has not changed over the period. In Hall plot analysis, we trace slope changes of the curve. If the slope becomes steeper, that is an indication of a flow resistance development (formation plugging, wellbore scaling etc.) and if the slope becomes shallower, this would indicate formation stimulation.

Although the Hall plot is a powerful tool to monitor water injector analysis, sometimes the slope changes are too subtle to detect that the situation has changed. Izgec and Kabir (2007) proposed a use of Hall derivative as a new diagnostic method. The Hall derivative is given by

$$D_{HI} = \frac{d \int \left(p_{wf} - \overline{p}\right) dt}{d \ln\left(W_i\right)} \qquad (5)$$

Plotting Hall integral and derivative on the same graph makes diagnostic of injection performance easier. A separation of two curves is indicative of flow condition changes. If the derivative curve overrides the integral, it implies a positive skin. If the derivative goes below the integral, it would indicate a negative skin. The Hall plot of Awi18-1 during stimulation is shown in **Figure 6** along with its derivative curve. Markers of fall off test timing are also shown. The plots show a downward separation of the Hall derivative curve from Hall integral. The deviation of these two curves becomes wider as we inject more water, which implies increase in injectivity. Timing of large injectivity improvement according to Hall plot occurs between second and fourth fall off test. This is consistent with interpretation from fall-off tests data previously discussed.

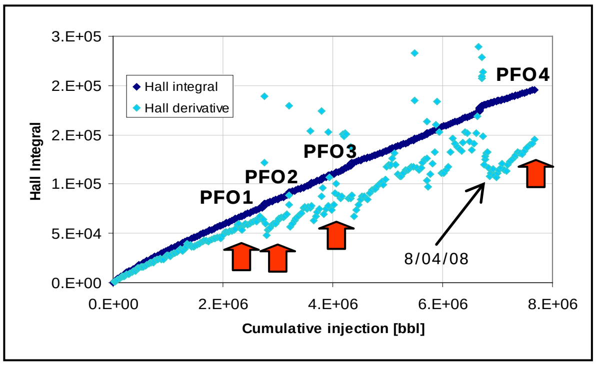

Figure 6: Hall and Hall derivative plot during Awi 18-1 stimulation

2.4 Post-Stimulation Test and Operation of Awi 18-1

As mentioned earlier, a final injectivity test was conducted before hydraulic stimulation ended. Compared to the initial injectivity index (**Figure 7**), it improved by 180% and the wellhead pressure at zero flow has declined from 400 psia to 100 psia. Injection capacity of Awi 18-1 has improved up to tenfold, suggesting that injection stimulation has not only improved permeability but has also established a channeling to a system with lower pressure.

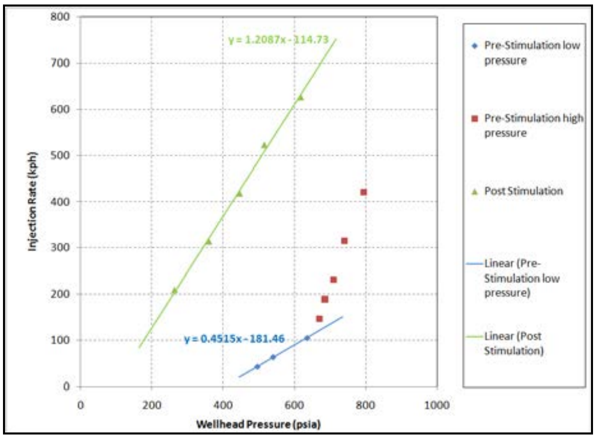

Figure7: Injectivity Index of Awi 18-1 before and after stimulation

Since completion of hydraulic stimulation in Sep 2008, Awi 18-1 well has been used as injector for power plant condensate water. Conducting regular injectivity test or pressure transient tests became more challenging once the well was put on service. Therefore, Hall plot is used for a second time for continuous monitoring of well injectivity.

The Hall plots (**Figure 8**) suggest some further improvement occurred after 15 million barrels of water injection as derivative goes below the Hall integral curve. The derivative plot is then parallel with the Hall integral plot which is usually observed when an injector has some channeling to a pressure sink. Plot of recent daily operation data in 2013 (**Figure 9**) also suggests a similar mechanism wherein the well injectivity has improved but the improvement is not caused by increased II. The operational data plot parallel to the injection curve measured in 2008; there is no change in slope but there is a further reduction in pressure. This implies that improvement of well injection capacity is cause by well connection to system with lower pressure.

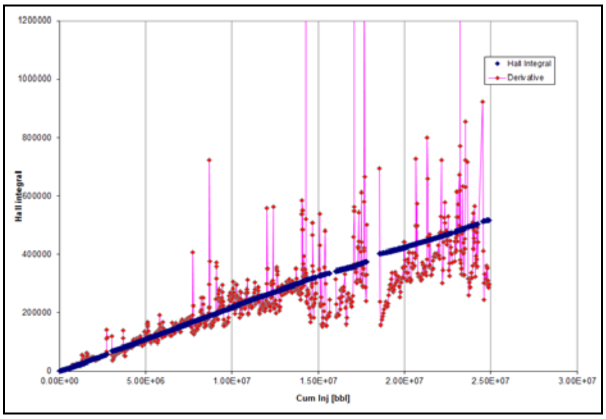

Figure 8: Hall and Hall derivative plot during Operation of Awi 18-1 as Condensate Water injection

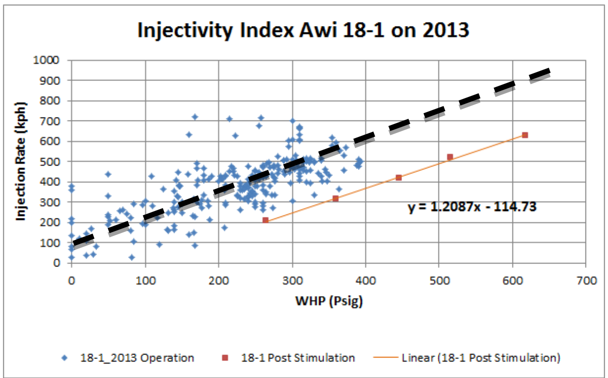

Figure 9: Plot of 2013 operation data and injectivity curve from post-stimulation test in 2008

Unlke hydraulic stimulation process, during injection operation the maximum achievable pressure at wellhead is 500 psi which is below the intital fracture opening pressure of 650 psi. Considering low pressure injection, the increase of injectivity of Awi 18-1 during operation is believed to be a result of opening fractures from the thermal contraction effect. Fractures that carry cool injectate experience progressive increases in through-going permeability. As the rock wall cools off, it shrinks back from the open fracture. Rock contraction can be expressed by $C = \alpha\ \Delta T$ where C is the reduction in size per unit length, α is the linear thermal expansivity and ΔT is the temperature change. Since thermal stress is related to temperature changes, the effect of thermal stimulation is controlled by difference between high rock temperature (>400 ^{o}F) with low temperature injectate (80 – 100 ^{o}F).

3. PLAN FOR NEXT STIMULATION PROGRAM

Four wells have been drilled at Awi 18 pad location to implement outfield brine injection program. Awi 18-1 is the first well drilled in 2006 and underwent long-term hydraulic stimulation treatment. The other three wells were constructed in 2012 – 2013. A study with reservoir simulation suggests that the minimum amount of produced brine that needs to be injected outside of Awibengkok reservoir to optimize field performance is 1800 kph. As per Table 2, the current total capacity of the Awi-18 wells for brine injection is 2290 kph. Despite higher than minimum requirement, we see some value to increase further the capacity of outfield brine injection system to 3000 kph. The biggest value comes from system reliability improvement by having extra injection capacity.

Table 2: Injection Capacity of Awi 18 wells at wellhead pressure of 450 psi.

Well	Capacity for condensate injection (kph)	Capacity for brine injection (kph)
Awi 18-1	620	600
Awi 18-2	180	160
Awi 18-3	345	300
Awi 18-4	1380	1230
Total	***2525***	***2290***

Considering the previous success at Awi 18-1, the hydraulic stimulation is selected to improve overall capacity of outfield brine injection system to 3000 kph. Next step in planning stimulation program is to define the candidate wells providing several limitations and key success factor such as:

- Maximum condensate water supply to Awi 18 location is 35 BPM (720 kph)
- More effective stimulation when pressure applied is above fracture opening pressure
- Maximum allowable pressure at the wellhead considering well integrity and potential fracture dilation to the surface
- Operation cost

Injection curve from both injectivity test and historical operation data would be a good tool for initial filtering of well candidate for stimulation. Awi 18-1 would not be good candidate for further hydraulic stimulation. According to updated injection chart (**Figure 9**), water supply required to obtain fracture opening pressure of 650 psi at the wellhead is 950 kph. This is above the maximum attainable water supply. In addition, pumping units with higher capacity than what was used before will be required. This will impact to increased cost. The other well, Awi 18-2RD, is a good candidate for hydraulic stimulation. Injection test and operation data (**Figure 10**) suggest the fracture opening pressure of 700 psi at the wellhead. Water injection requirement to attain fracture opening pressure is 300 kph, which is within achievable supply rate.

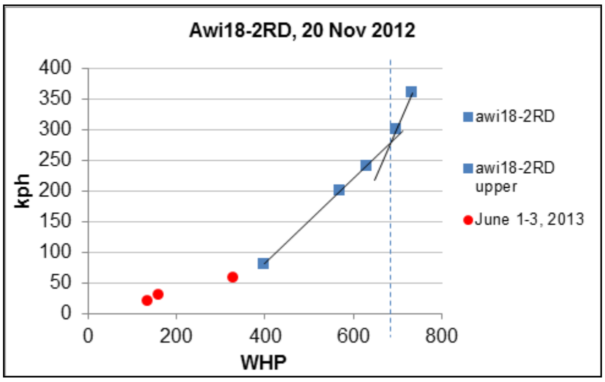

Figure 10: Plot of Awi 18-2RD Injectivity Test Data

4. SUMMARY AND CONCLUSSIONS

- Stimulation histories from Awi 18-1 field reveal that natural fracture permeability in the geothermal system can be stimulated by water injection through thermal and hydraulic forces to open new and existing cracks. This has resulted in a significant improvement in the injection capacity of the Awi 18-1 well.

- When planning a well stimulation project, collecting information from different sources and doing an integrated interpretation makes possible a better characterization of the process. Combined use of Hall plot, MEQ events, Injectivity test and Pressure Fall-off can give consistent picture of progress and effectiveness of stimulation.

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