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Well Stimulation Techniques Applied at the Salak Geothermal Field

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ABSTRACT

The Salak field is the largest developed geothermal resource in Indonesia operated by Chevron. Steam production levels in Salak have been successfully maintained at or above the rated power plant capacity since 1994. Infill drilling has been the primary tool to meet the steam supply target. Besides formulating steam supply strategy, formulating injection strategy is also a key parameter for field management in a liquid dominated geothermal resource like Salak. It is recognized that Salak reservoir performance would be improved through moving injection from current, infield locations, to outfield locations. During the most recent drilling campaign, several delineation wells have been drilled outside of the proven reservoir boundary to replace existing injectors. Drilling delineation and new infill wells in a naturally fractured volcanic reservoir with varying mineralogy over wide temperature range has always been challenging. A number of newly drilled wells have low permeability which limits their production or injection capacity. The low permeability could be either induced by damage which occurred while drilling or due to inherent features. Several stimulation techniques such as massive water injection, thermally-induced, slow-acidizing, and coiled-tubing acidizing have been applied to enhance permeability of these sub-commercial wells with various degrees of success. Application of these stimulation techniques has replaced the old practice of redrilling or side-tracking new wells with low permeability. This paper describes the designs, processes, and outcomes of applied stimulation techniques as well as techniques to interpret surveillance data collected during stimulation.

1. INTRODUCTION

The drilling process at Salak geothermal field has evolved from drilling the reservoir section with water to drilling the reservoir section with mud to minimize the risk of stuck pipe which occurred in the previous two drilling campaigns. More effort has also been made to maintain mud properties such as weight and viscosity for the duration of drilling despite high loss rates. However, ten infill production wells drilled in Salak during the 2004 – 2009 drilling campaign show indications of low production capacities. The completion and flow tests suggest that these wells produce 70 kilo-pound per hour (kph) or less. The expected initial steam production at commercial wellhead pressure of those wells is 150 – 190 kph. The drilling records indicate that nine of those wells were drilled with water based mud (WBM) losses of 20,000 – 300,000 bbls during the drilling at reservoir section. Invasion of WBM and drilling cuttings to fractures is believed to cause formation damage to those wells. Analysis of the pressure transient data of some of the wells revealed positive skin values that confirmed the presence of formation damage. In the meantime, one other sub-commercial infill well drilled in 2004, Awi 11-6OH, has not suffered formation damage. This well naturally had poor connectivity to the large natural fracture in the main reservoir. Massive water injection and thermally-induced stimulations were applied in 2004 to Awi 11-6OH and one other well with a formation damage problem (Awi 11-5). Permeability of those wells improved but not to the point required for turning them into commercial wells. The next massive water injection stimulation at Awi 11-6OH was then modified by acidifying the injected water. This stimulation technique is called as Slow Acid Stimulation. Subsequent approaches to Awi 11-5 and the other wells with formation damage problems were different. Coiled tubing acid stimulations were applied to them and successfully improved their production performance to commercial level.

As part of reformulating injection strategy in Salak, several delineation wells have also been drilled to the west of proven reservoir during the current drilling campaign. Based on geophysical surveys (MT, TDEM and gravity), this area's proximity to the main brine-producing area of the field and the lower elevation area of the west of the Salak reservoir made it the best candidate for brine injection. However, the measured injectivity index of 0.5 kph/psi or less at those wells is below the acceptable level for a commercial injector. The completion tests suggest that the low injectivity is due to inherent features and not due to formation damage. A long-term hydraulic stimulation has been conducted and successfully improved the injection capacity of the wells around tenfold.

2. THERMALLY- INDUCED STIMULATION

Awi 11-5 and AWI 11-6OH were drilled to more than 8000 ft deep in the central part of Salak reservoir with high temperature (455 to 535 ^{o}F) and close proximity to permeable wells. Initial injection and production tests indicate that both wells have very low permeability due to poor connectivity to the large natural fracture in the main reservoir. The first stimulation technique applied at those wells was thermally-induced stimulation wherein 330 ^{o}F fluid (hot brine) and 100 ^{o}F fluid (condensate water) were injected alternately every 1 - 4 weeks at flow rates ranging from 630 kph for condensate up to 2000 kph for hot brine. As is seen in Figure-1, an injectivity index test suggests that we can hydraulically induce permeability by injecting 630 kph (~30 BPM) of water into the well allowing penetration of injected cold condensate or brine deep into the fracture.

Thermal fracturing can certainly be induced by cycling injection of cold fluid with either hot fluid or fluid from the well. The cycling- injection option was selected due to its simpler operation. Producing steam from Awi 11-5 and Awi 11-6OH wells would require months of heating-up processes. One big challenge from this project was to predict the extent of thermal fracturing and the change in permeability that would occur as a result of the thermal cycling operation. A series of injection tests were conducted at the end of each stimulation cycle to observe the evolution of the injectivity index (II, kph/psi) of the wells.

After 2 injection cycles, the injectivity index of Awi 11-6OH increased from 1.1 to 2.2 kph/psi (Figure 2) but then the subsequent injection cycles resulted in no injectivity increase. A stepped increase of injectivity (from 0.6 to 1.4) was also observed during early injection cycles at Awi 11-5 (Figure 3) and continued to increase at a lower gradient in the subsequent injection cycles. The overall injection stimulation program at Awi 11-5 and 11-6OH had to be terminated in March 2005 since the cooling impact from injection of condensate and brine had lowered productivity of surrounding production wells.

The increase of injectivity of both wells, especially at early stimulation periods, is believed to be a result of opening fractures the from 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 (Melosh, 2004), the effect of thermal fracturing stimulation in some cases is controlled by the in-situ rock temperature. The higher rock temperatures at Awi 11-5 (Figure 4) could explain the higher slope of the injectivity increase compared to that of Awi 11-6OH.

Other dissimilarities that lead to different stimulation outcomes between those wells are the total water injection and thermal cycle period. Throughout the project, 3.4 and 4.4 million barrels of condensate and brine respectively were injected at Awi 11-5. On the other hand, cumulative condensate and brine injections at Awi 11-6OH were 1.6 and 3.7 million barrels. A Longer cold condensate injection period of the thermal cycle was applied to Awi 11-5. With a larger volume of cumulative water injection and longer cycle period, thermal fracture at Awi 11-5 may expand further than that of Awi 11-6OH and result in a greater increase in injectivity.

3. SLOW ACID STIMULATION

During thermally-induced stimulation at Awi 11-6OH, the trend of injectivity improvement was no longer observed after Feb 2005. Wellbore simulation suggests that Awi 11-5 and 11-6OH wells will not be able to deliver steam at commercial wellhead pressure with an II of 2 kph/psi. It was then decided to modify the ongoing thermally induced stimulation with chemical treatment using hydrochloric acid (HCL) in a process called Slow Acid Stimulation (SAS). HCL was selected due to abundant calcite on the formation vein and matrix. The SAS process was started with a pre-flush step wherein 4000 gallons of 15% HCL was bullhead pumped to the well. The second step was a bullhead injection of acidified cold water (condensate, 80 ^{o}F). At this step, 2.7 gpm of inhibited 15% wt. HCl was injected to acidify 30 bpm of condensate to give an injectate solution of pH 3.0 – 4.0. The first attempt was made shortly after completing the pre-flush. However, the acid injection was stopped due to severe leakage at a low point section of the injection pipe. The 15% HCl from the pre-flush was trapped for a period longer than the corrosion inhibitor lifetime and corroded the pipe. The 2nd attempted acid injection had to be immediately stopped due to lost prime on the dosing pumps. It was found that the piston rod and spring were severely corroded. A decision was taken to replace the dosing pump with a BJ 35-8-5 Twin Skid Pumping Unit. With this bigger pumping unit, the concentration of inhibited acid was lowered to 1% wt HCl but pump rate was increased to 41 gpm to acidify 29 BPM of injected condensate to a pH of 3 - 4. A total of 0.3 million barrels of low pH condensate was injected in a 1 week period. No corrosion was observed at the wellhead.

The last step of SAS treatment was bullhead injection of acidified hot water (brine, 350 ^{o}F)). Here, the inhibited 1% wt HCl was injected at rate of 39 gpm to acidify 59 BPM of brine. Treatment with brine was initially scheduled for 1 week. However, the program was stopped 3 days early as Ultrasound Thickness Gauge (UTG) measurement indicated a rapid corrosion process at the wellhead casing. The wellhead casing thickness was reduced from 13 mm to 10 mm. To verify the cause of wellhead corrosion, pure brine (without acid) was injected for next 3 days. The corrosion process stopped as the acid injection stopped. It was apparent that the thinning of the wellhead casing was not due to corrosion erosion from high rate brine injection. Thinning was caused by failure of the corrosion inhibitor at the high temperatures used.

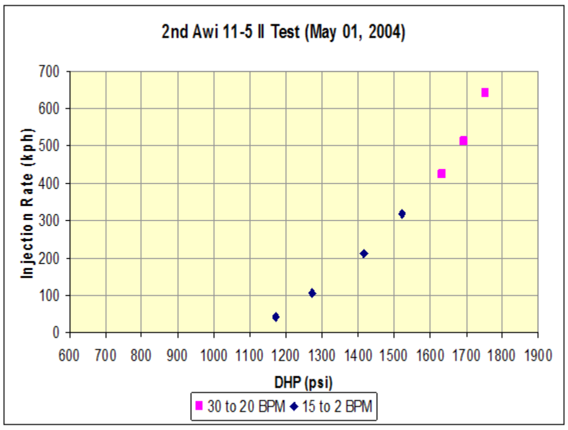

Figure 1: Data from a step-rate injection test at Awi 11-5 shows the increase of injectivity at higher injection rates

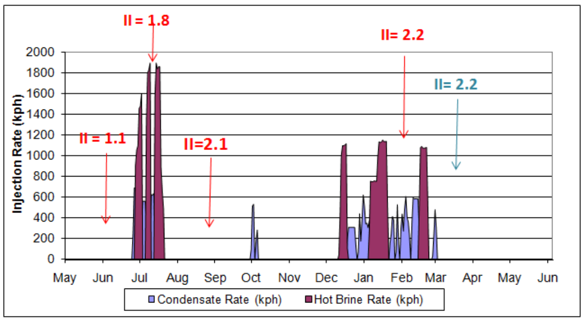

Figure 2: Injection history at Awi 11-6OH and evolution of its injectivity index value during thermally-induced stimulation

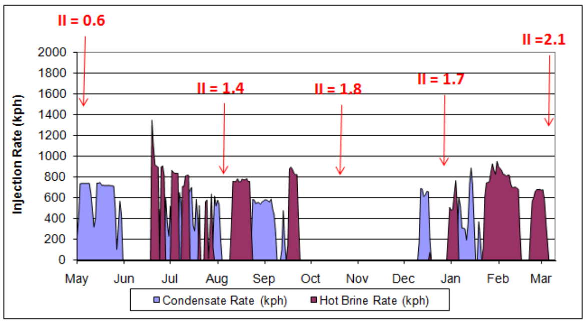

Figure 3: Injection history at Awi 11-5 and evolution of its injectivity index value during thermally-induced stimulation

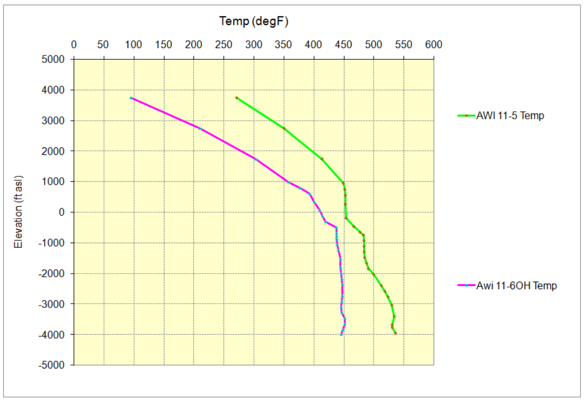

Figure 4: Stabilized Formation Temperature at Awi 11-5 and 11-6OH

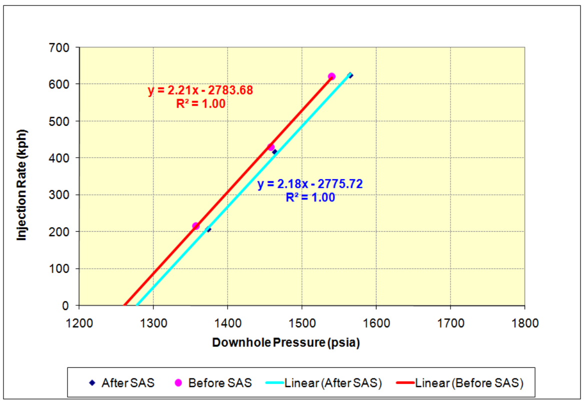

Figure 5: Plot of injection rate vs. measured pressure. II of Awi 11-6OH remained at 2.2 kph/psi after SAS treatment

Table-1: Candidate Wells for Acid Stimulation and their characteristics.

Well	Cumulative drilling mud loss (Bbls)	Injectivity Index (kph/psi)	Initial Production (kph)*
Awi1-9	39,000	2.3	0
Awi8-7	94,500	2.6	70
Awi8-8	24,500	2.9	0
Awi8-10	103,500	6.6	55
Awi10-3	200,000	3.3	60
Awi11-4	27,200	4.9	0
Awi11-5	23,700	2.1	0
Awi11-6RD	72,700	1.0	0
Awi19-2	276,000	1.7	0

**Production at commercial wellhead pressure*

Figure 5 shows that the injectivity index (II) of Awi 11-6OH after SAS treatment had not increased. A flow test conducted 2 months after the injection test revealed that the well still could not produce steam at commercial wellhead pressure. The relatively low acid concentration of injectates (pH of 3 – 4) may not have been strong enough to dissolve calcite deposited in the formation. Bullhead injection might have contributed also to the downside outcome. Some portion of injected high concentration acid on the pre-flush and acidified condensate / brine might have leaked to the non effective fractures behind the slotted liner and reduced the portion of treatment fluids that flowed to the expected fractures.

4. COILED TUBING ACID STIMULATION

4.1 Well Candidate Selection

Candidate selection is primarily based on the production or injection characteristics. In a new well, low injectivity index, poor production and amount of drilling mud and cuttings lost to the reservoir formation while drilling are the best indication that the well is a strong candidate for acidizing. Other factors to consider for candidate selection would be feasibility of stimulation, chance of success, project economics and value of information. Table-1 describes characteristics of the selected wells before being stimulated.

4.2 Selected HF Acid System and Volume

Hydrofluoric acid is commonly used to stimulate sandstone formations in the oil and gas industry and has also been applied in geothermal fields. The treatment chosen for wells in Salak field utilized an HF acid system offered by BJ Services that is known as Sandstone Acid.

The acid treatment was designed with a load of 45 - 60 gallons of 7.5 - 15 wt. HCl per linear foot for the pre-flush and 90 - 120 gallons of 5 - 9% wt. Sandstone Acid per linear foot for the main flush. Two wellbore volumes of fresh water was pumped into the well after completing the main-flush step. HCl preflush is first placed in the zone of interest to remove calcium carbonate, iron carbonate or other calcareous minerals. Calcareous materials can form damaging precipitates when reacting with HF acid. In addition to removing calcareous materials, the preflush moves formation brine out of the near wellbore area. Contact between formation brine and HF acid systems can also result in damaging precipitates.

The reservoir temperature in Salak is over 450^{o}F, whereas standard acid inhibitors for HCl are only effective up to about 300^{o}F. Acid inhibition for zones above this temperature is in principle possible with organic systems, but the cost goes up considerably. In the case of CT Acidizing, the well was quenched with 30 bpm of fresh water for 48 hours prior to the coiled tubing running in the hole. Although the quenching cools the well, the magnitude of the cooling was essential for correct design of the corrosion inhibitor loadings. Therefore, prior to pumping acid, a temperature survey was run in the hole using coiled tubing. The acid treatment at the deepest target interval was then simulated by pumping water through coiled tubing and the annulus at rates expected during actual job. The understanding of downhole temperatures under actual treatment conditions translated to optimization of corrosion inhibitor loading.

4.3 Targeting the Feed Zones

All feedzones (FZ) identified from a pre-acid PTS (pressure – temperature-spinner) survey in general are the target interval for acid stimulation. However, formation must also be considered. Stimulating a feedzone at a low temperature formation potentially decreases steam production. A pre-acid PTS survey at Awi 8-8 well identified 5 permeable zones 2 of which were located in the low temperature region (Figure 6). A wellbore simulation was then run to observe the degree of productivity index enhancement from stimulating low and high temperature feedzones. Simulation output suggested that stimulation of the 5 feedzones including low temperature ones would result in lower steam production than that of only stimulation of the 3 high temperature feedzones (Figure 7). Based on this evaluation, the upper 3 feedzones were selected as a target interval for acid stimulation at Awi 8-8. Other factors that need to be taken into account are temperature limitation of corrosion inhibitor and delta pressure between formation and wellbore (under treatment conditions). Feedzones must be cooled off to the safe temperature and be conditioned to attain wellbore pressure higher than the pressure at the formation to be treated.

Coiled tubing is necessary to place the acid via a dedicated conduit adjacent to the desired zones of interest. Additionally, coiled tubing can be reciprocated across the zone of interest to uniformly cover the zone with treatment fluids. The largest size available (2" OD) was used for acid stimulation in Salak to maximize pump rates, thereby potentially improving placement and decreasing treatment time.

4.4 Stimulation Result

Coiled tubing acidizing in Salak achieved a 100% success level. Post acidizing injection and production tests are the primary tools to measure the wellbore improvement from acid stimulation. Those tests confirmed the increase of injectivity or productivity indices at all treated wells. Their steam deliverability also significantly increased with total steam gain of 457 kph (27.7 MWe). All of the acidized wells have since been successfully put on to production.

Three different sandstone acid formulas were exercised:

- 5% wt HF with 90 gallon/ft-treatment loading on the main flush and 7.5% HCL with 45 gal/ft-treatment loading on the pre-flush.
- 5% wt HF with 120 gallon/ft-treatment loading on the main flush and 7.5% HCL with 60 gal/ft-treatment loading on the pre-flush
- 9% wt HF with 120 gallon/ft-treatment loading on the main flush and 15% HCL with 60 gal/ft-treatment loading on the pre-flush

Results from this exercise suggest that improvement of productivity index is sensitive to both: acid volume and acid concentration (Figure 8). Treatment with maximum HF acid concentration and load (9% and 120 gal/ft) gave the highest permeability (PI) improvement. However, it is unknown whether increasing the acid concentration or volume load will still improve permeability further. It is also unknown whether the acid treatment completely removed all the drilling damage. To address this issue the 2^{nd} acid job was done at the Awi 11-6RD well. A post-acidizing PTS survey showed that the injectivity index of Asi 11-6RD had not increased after the 2^{nd} acid stimulation.

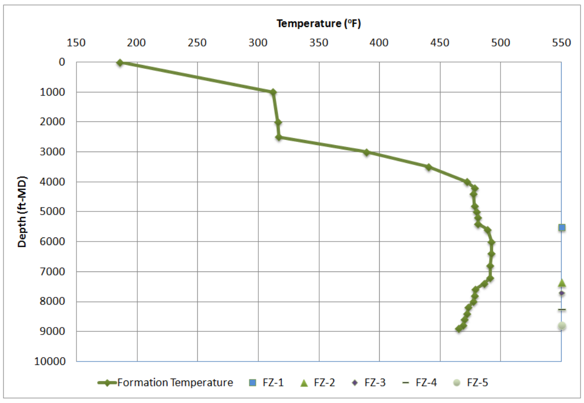

Figure 6: Temperature Survey at Awi 8-8 shows low temperature regions below 7500 ft.

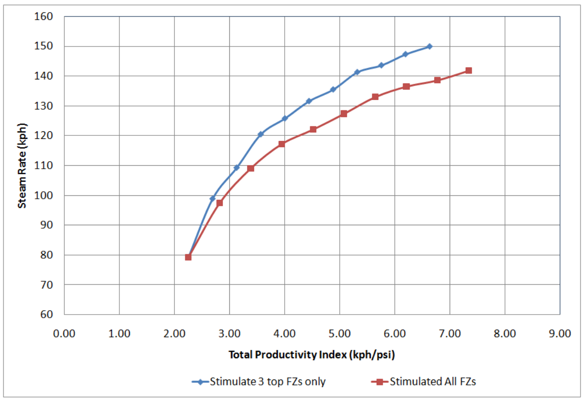

Figure 7: Results from sensitivity study on the effect of PI enhancement of steam production for different stimulation strategies at Awi 8-8 well

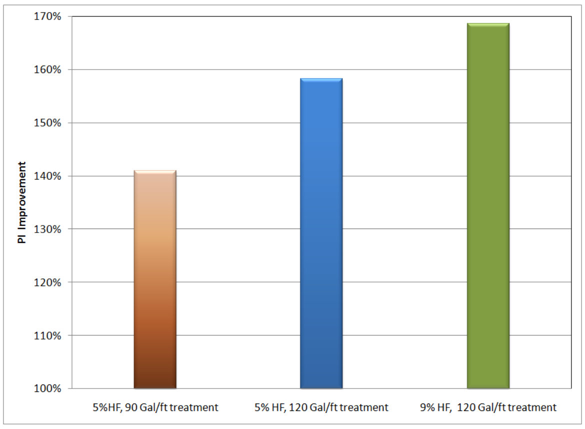

Figure 8: Average PI improvement from 3 different sandstone acid formulas

Table-2: Coiled Tubing Acid Stimulation Results

Well	Main Flush Acid Treatment	Production Chracteristics			
		PI (kph/psi)		Steam Production (MWe)*	
		Pre-Job	Post-Job	Pre-Job	Post-Job
AWI 8-7	5%HF, 90 Gal/ft treatment	2.1	5.3	4.2	9.8
AWI 8-8	5%HF, 90 Gal/ft treatment	2.3	5.3	0	7.8
AWI 10-3	5% HF, 120 Gal/ft treatment	2.4	4.4	3.6	8.0
AWI 1-9	5% HF, 120 Gal/ft treatment	0.9	2.8	0	8.2
AWI 8-10	9% HF, 120 Gal/ft treatment	2.5	11.7	3.3	7.5
AWI 11-4	9% HF, 120 Gal/ft treatment	3.5	7.4	0	4.4
AWI 11-5	9% HF, 120 Gal/ft treatment	1.6	3.8	0	5.4
AWI 11-6RD	9% HF, 120 Gal/ft treatment	0.8	3.7	0	3.6
AWI 19-2	9% HF, 120 Gal/ft treatment	0.6	1.6	0	3.2
2nd Acid Job AWI 11-6RD	9% HF, 120 Gal/ft treatment	3.7	3.7	3.6	3.6
TOTAL				3.3	32.2

*Production at commercial wellhead pressure

Table-3: Treatment record from Awi 11-6RD Well

Time [min]	q -CT [bpm]	q -AN [bpm]	Pti [psi]	Fluid
2	5.09	4.91	1361.69	Pre-flush (HCl)
4	5.08	5.04	1345.08	Pre-flush (HCl)
6	5.07	5.56	1338.08	Pre-flush (HCl)
8	5.07	5.53	1335.67	Pre-flush (HCl)
10	5.08	5.36	1332.75	Pre-flush (HCl)
12	5.08	5.09	1331.92	Pre-flush (HCl)
14	5.08	5.03	1326.33	Pre-flush (HCl)
16	5.07	5.11	1329.75	Pre-flush (HCl)
18	5.06	5.13	1370.58	Pre-flush (HCl)
20	5.08	5.16	1372.75	Pre-flush (HCl)
22	5.08	5.15	1366.42	Pre-flush (HCl)
24	5.07	5.04	1373.08	Pre-flush (HCl)
26	5.07	4.98	1382.83	Pre-flush (HCl)
28	5.06	4.97	1389.67	Pre-flush (HCl)
30	5.06	4.93	1403.33	Pre-flush (HCl)
32	5.06	4.96	1414.25	Pre-flush (HCl)
34	5.06	4.91	1415.33	Pre-flush (HCl)
36	5.06	4.92	1423.42	Pre-flush (HCl)
38	5.06	5.00	1416.00	Pre-flush (HCl)
40	5.06	5.05	1371.75	Main (SSA)
42	5.06	5.14	1368.58	Main (SSA)
44	5.06	5.18	1364.00	Main (SSA)
46	5.06	5.21	1356.75	Main (SSA)
48	5.07	5.21	1358.33	Main (SSA)
50	5.08	5.19	1354.50	Main (SSA)
52	5.08	5.13	1349.50	Main (SSA)
54	5.08	5.12	1341.17	Main (SSA)
56	5.08	5.05	1339.00	Main (SSA)
58	5.08	5.06	1338.58	Main (SSA)
60	5.10	5.04	1262.75	Main (SSA)
62	5.09	5.05	1215.92	Main (SSA)
64	5.08	5.04	1226.08	Main (SSA)
66	5.08	5.03	1241.92	Main (SSA)
68	5.08	5.02	1240.58	Main (SSA)
70	5.07	5.03	1246.25	Main (SSA)
72	5.09	5.07	1254.67	Main (SSA)
74	5.04	5.06	1245.25	Main (SSA)
76	5.01	5.05	1303.08	Main (SSA)
78	4.97	5.00	1492.08	Main (SSA)
80	5.02	5.01	1288.50	Main (SSA)
82	5.03	5.03	1277.50	Main (SSA)
84	5.03	5.05	1275.75	Main (SSA)
86	5.03	5.05	1277.50	Main (SSA)
88	5.02	5.03	1280.25	Main (SSA)
90	5.02	4.99	1273.33	Main (SSA)
92	5.04	4.99	1278.92	Main (SSA)
94	5.05	5.00	1275.00	Main (SSA)
96	5.05	4.99	1277.17	Main (SSA)
98	5.04	5.01	1267.33	Main (SSA)
100	5.05	4.98	1211.17	Main (SSA)
102	5.04	5.00	1216.50	Main (SSA)
104	5.03	5.00	1247.25	Main (SSA)
106	5.02	4.96	1280.17	Main (SSA)
108	5.03	4.99	1271.17	Main (SSA)
110	5.03	5.04	1263.67	Main (SSA)
112	5.04	5.00	1257.00	Main (SSA)
114	5.03	5.01	1260.25	Main (SSA)
116	5.02	5.12	1345.33	Main (SSA)
118	4.97	5.12	1678.75	Main (SSA)
121	4.99	5.08	1593.67	Main (SSA)
126	4.05	5.01	1925.13	Water
131	3.53	5.01	2132.90	Water
136	3.52	5.02	2200.37	Water
141	3.55	5.04	1841.27	Water
146	3.55	7.75	1568.97	Water
151	3.51	10.30	2139.83	Water
156	3.52	8.08	2187.07	Water
161	3.52	8.14	2191.93	Water
166	3.50	10.05	2166.03	Water
171	3.50	10.08	2160.19	Water

Table-4: Treatment record from Awi 11-6RD Well

Time [min]	q -CT [bpm]	q -AN [bpm]	Pti [psi]	Fluid
2.5	5.13	5.01	1554.53	Pre-flush (HCl)
5.0	5.08	5.01	1523.08	Pre-flush (HCl)
7.5	4.89	5.01	1431.62	Pre-flush (HCl)
10.0	5.01	5.01	1473.05	Pre-flush (HCl)
12.5	5.13	5.01	1547.25	Pre-flush (HCl)
15.0	5.09	5.01	1545.81	Pre-flush (HCl)
17.5	5.13	5.01	1549.34	Main (SSA)
20.0	5.13	5.01	1528.89	Main (SSA)
22.5	5.13	5.01	1519.43	Main (SSA)
25.0	5.13	5.01	1496.98	Main (SSA)
27.5	5.14	5.01	1502.31	Main (SSA)
30.0	5.15	5.01	1509.29	Main (SSA)
32.5	5.15	5.01	1525.92	Main (SSA)
35.0	5.11	5.01	1535.34	Main (SSA)
37.5	5.12	5.01	1535.63	Main (SSA)
40.0	5.13	5.01	1515.14	Main (SSA)
42.5	3.08	5.01	608.39	Main (SSA)
45.0	2.86	5.01	671.78	Main (SSA)
47.5	3.97	5.01	1042.22	Main (SSA)
50.0	4.98	5.01	1453.15	Main (SSA)
52.5	4.98	5.01	1432.70	Main (SSA)
55.0	4.99	5.01	1427.64	Main (SSA)
57.5	5.03	5.01	1405.14	Main (SSA)
60.0	5.11	5.01	1315.65	Main (SSA)
62.5	5.14	5.01	1384.41	Main (SSA)
65.0	5.02	5.01	1330.32	Main (SSA)
67.5	4.82	5.01	1331.62	Main (SSA)
70.0	4.86	16.03	1976.00	Water
72.5	4.51	16.03	3024.00	Water
75.0	3.77	16.03	2763.00	Water
77.5	3.60	16.03	2498.00	Water
80.0	3.58	16.03	2486.00	Water
82.5	3.57	16.03	2456.00	Water
85.0	3.56	16.03	2447.00	Water
87.5	3.57	16.03	2449.00	Water
90.0	3.57	16.03	2485.00	Water
92.5	3.10	16.03	1710.00	Water

4.5 Real Time Acid Treatment Analysis

The performance of the acid treatments and the adequacy of the treatment design have been conventionally evaluated by measuring injectivity or productivity before and after stimulation. A real-time acid treatment performance analysis was applied to the most recent acid stimulation campaign. On this analysis, variant skin factor and/or injectivity change in the course of acid stimulation were evaluated. By tracking the real-time performance, improvements for future acid treatment design were identified.

Zhu and Hill (1998) applied line source solution to real-time skin factor analysis and furthermore they took into consideration the multiple rate changes during acid treatment. A study by Yoshioka (2008) suggests that the Zhu and Hill method provides the most consistent result for the real conditions at the wells. The pressure transient response to multi-rate injection is given as (Earlougher, 1977).

$$\frac{p_i - p_{wf}}{q_N} = m\Delta t_{\text{sup}} + b \tag{1}$$

where

$$m = \frac{162.6B\mu}{kh} \tag{2}$$

$$b = m\left[\log\left(\frac{k}{\phi\mu c_t r_w{}^2}\right) - 3.23 + 0.87s\right] \tag{3}$$

$$\Delta t_{\text{sup}} = \sum_{j=1}^{N} \frac{\left(q_j - q_{j-1}\right)}{q_N} \log(t_N - t_{j-1}) \tag{10}$$

Table-5: Treatment record from Awi 11-6RD Well

Time [min]	q -CT [bpm]	q -AN [bpm]	Pti [psi]	Fluid
5.0	5.12	5.02	1432.06	Pre-flush (HCl)
7.5	5.11	5.02	1426.74	Pre-flush (HCl)
10.0	5.11	5.02	1417.03	Pre-flush (HCl)
12.5	5.1	5.02	1407.72	Pre-flush (HCl)
17.5	5.12	5.02	1386.69	Pre-flush (HCl)
20.0	5.12	5.02	1340.99	Pre-flush (HCl)
22.5	5.08	5.02	1323.67	Pre-flush (HCl)
25.0	5.08	5.02	1316.96	Pre-flush (HCl)
30.0	5.12	5.02	1308.94	Pre-flush (HCl)
32.5	5.07	5.02	1291.23	Pre-flush (HCl)
37.5	5.08	5.02	1282.21	Pre-flush (HCl)
40.0	5.09	5.02	1268.50	Pre-flush (HCl)
42.5	5.14	5.02	1287.18	Pre-flush (HCl)
45.0	5.12	5.02	1136.47	Pre-flush (HCl)
50.0	5.1	5.02	1223.45	Pre-flush (HCl)
52.5	5.1	5.02	1209.13	Pre-flush (HCl)
57.5	5.13	5.02	1253.86	Pre-flush (HCl)
65.0	5.08	5.02	1244.90	Pre-flush (HCl)
67.5	5.04	5.02	1260.69	Pre-flush (HCl)
70.0	5.1	5.02	1276.02	Pre-flush (HCl)
77.5	5.07	5.02	1259.10	Pre-flush (HCl)
80.0	5.06	5.02	1262.78	Pre-flush (HCl)
85.1	5.13	5.02	1262.50	Pre-flush (HCl)
90.0	5.11	5.02	1248.83	Main (SSA)
97.6	5.05	5.02	1341.92	Main (SSA)
100.0	5.06	5.02	1334.43	Main (SSA)
102.6	5.05	5.02	1326.33	Main (SSA)
110.1	5.06	5.02	1303.46	Main (SSA)
112.6	5.06	5.02	1285.57	Main (SSA)
115.1	5.06	5.02	1292.08	Main (SSA)
120.1	5.17	5.02	1183.31	Main (SSA)
122.6	5.17	5.02	1183.66	Main (SSA)
125.1	5.14	5.02	1182.30	Main (SSA)
130.1	4.98	5.02	1162.56	Main (SSA)
132.6	5.02	5.02	1182.19	Main (SSA)
135.1	5.02	5.02	1205.22	Main (SSA)
142.6	5.17	5.02	1351.90	Main (SSA)
147.6	4.93	5.02	1290.51	Main (SSA)
150.1	5.06	5.02	1346.48	Main (SSA)
157.6	5.08	5.02	1314.50	Main (SSA)
160.1	5.06	5.02	1287.05	Main (SSA)
162.6	5.04	5.02	1328.99	Main (SSA)
170.1	5.04	5.02	1193.01	Main (SSA)
172.6	5.11	5.02	1205.95	Main (SSA)
177.6	5.1	5.02	1180.43	Main (SSA)
182.6	5.1	5.02	1150.92	Main (SSA)
187.6	5.03	5.02	1592.12	Main (SSA)
190.1	5.04	5.02	1312.97	Main (SSA)
197.6	5.04	5.02	1340.68	Main (SSA)
200.1	5.04	5.02	1351.92	Main (SSA)
202.6	5.06	5.02	1369.16	Main (SSA)
210.1	5.06	5.02	1413.67	Main (SSA)
212.6	5.01	5.02	1773.30	Main (SSA)
217.6	2.94	16	1167.12	Main (SSA)
222.6	2.96	16	1164.45	Water
227.6	3.38	16	2046.17	Water
230.1	3.18	16	1746.03	Water
237.6	3.18	16	1739.23	Water
240.1	3.18	16	1735.09	Water
242.6	3.18	16	1727.95	Water
250.1	3.19	16	1714.14	Water
252.6	3.18	16	1711.00	Water
257.6	3.17	16	1703.72	Water
265.1	3.17	16	1684.91	Water
267.6	3.2	16	1725.77	Water
270.1	3.21	16	1718.64	Water
277.6	3.19	16	1710.83	Water
280.1	3.2	16	1707.69	Water
287.6	3.21	16	1699.27	Water
292.7	3.19	16	1698.09	Water

Table-6: Parameters for Awi 11-6RD Analysis

Reservoir/Fluid		Coiled Tubing/Wellbore	
Pr [psi]	1165	**rw [ft]**	1
B	1	**Tubing [in]**	2.1
Φ	0.1	**ε**	0.00001
Ct [1/psi]	0.000003	**L [ft]**	10500
h [ft]	100	**ρ [lbm/ft^3]**	68
k [md]	20	**Sp**	1.1
μ [cp]	0.5	**Z**	6300

Assuming that skin factor is the only variable during acid treatment, we can find b as the intercept on the plot of inverse injectivity $\left(p_i - p_{wf}\right)/q_N$, vs. the superposition time Δt_{sup}. Since the slope of this straight line, m is assumed to be invariant, skin evolution can be computed as

$$s = \frac{1}{0.87}\left[\frac{b}{m} - \log\left(\frac{k}{\phi \mu c_t r_w^{\ 2}}\right) + 3.23\right] \tag{4}$$

Then we update b from Eq. 4 as

$$b = \frac{p_i - p_{wf}}{q_N} - m\Delta t_{\text{sup}} \tag{5}$$

By applying the superposition time, we can remove the skin effects from the rate changes and trace the skin effect as flow restrictions or enhancements.

Tables 3 -5 show acid treatment data recorded at the treatment of Awi 11-6 (6250 – 6370 ft-MD), Awi 8-10 zone I (5330 – 5410 ft-MD) and Awi 8-10 zone III (5920 – 6170 ft-MD). Injection rates were recorded at coiled tubing and annulus, and the pressure response was recorded at the tubing head. Therefore, the bottomhole pressure needs to be calculated from the tubing pressure. The bottomhole pressure estimation procedure is discussed in Appendix A. Real-time analysis results from three different zones are shown in Figures 9, 10, and 11. The reservoir and coiled tubing parameters used in the analysis are listed in Tables 6 and 7.

Injection tests at Awi 11-6RD before and after the 2nd acid stimulation show that the injectivity index (II) remained at 4.43 kph/psi. This concludes that Awi 11-6RD did not improve from the treatment. In figure 9, a higher than initial skin factor is indicated from analysis by the Zhu and Hill method. In the meantime, the injectivity of the Awi 8-10 well had increased from 6.6 to 31.2 kph/psi. The acid treatment of this well was considered a great success. In figures 10 - 11, the Zhu and Hill method showed decreasing trends in skin factor during the acidizing at both treated zones. They show that skins increased during water flush but the skins became small again at the end of the treatment process.

The Injectivity index can be derived from the skin factor using the following formula:

$$II = \frac{0.000103kh}{\mu\left[\ln\left(r_e/r_w\right) + s\right]} \tag{6}$$

This injectivity index will change with the time variant skin. Then we normalized the injectivity index to the initial injectivity.

Table-7: Parameters for Awi 8-10 Analysis

Reservoir/Fluid		Coiled Tubing/Wellbore	
Pr [psi]	1050	**rw [ft]**	1
B	1	**Tubing [in]**	2.1
Φ	0.1	**ε**	0.00001
Ct [1/psi]	0.000003	**L [ft]**	10500
h [ft]	100	**ρ [lbm/ft^3]**	68
k [md]	30	**Sp**	1.1
μ [cp]	0.5	**Z**	5400

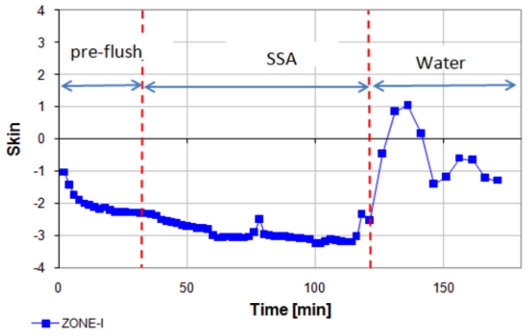

Figure 9: Skin evolution during 2nd Acid Stimulation at Awi 11-6

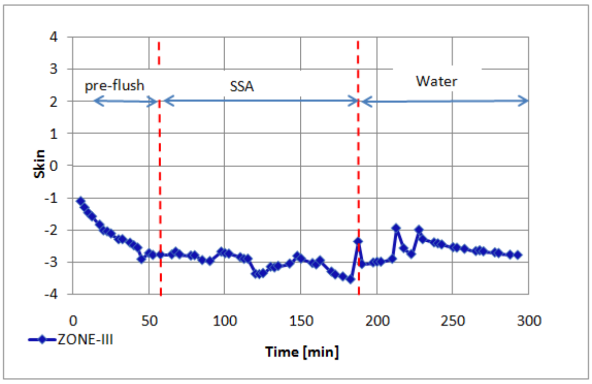

Figure 11: Skin evolution during Acid Stimulation at Awi 8-10 Zone-III

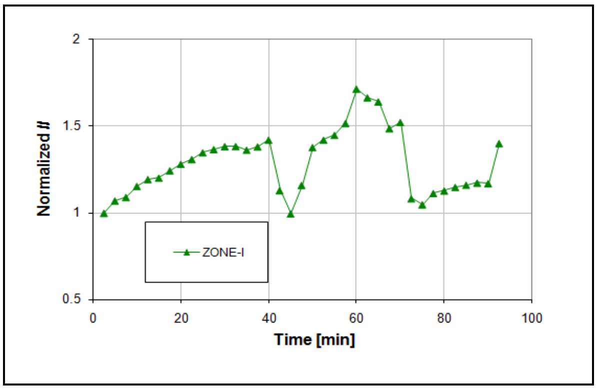

Figure 13: Normalized II evolution during Acid Stimulation at Awi 8-10 Zone-I

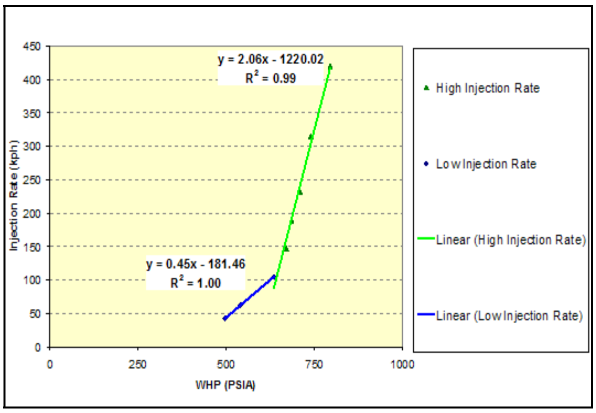

Figure 15: Initial Injectivity Test at Awi 18-1 conducted in Nov 2006

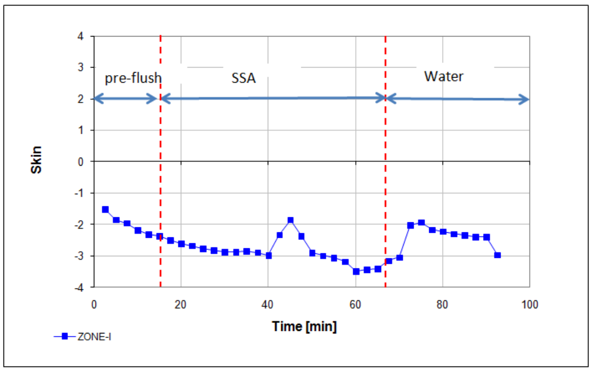

Figure 10: Skin evolution during Acid Stimulation at Awi 8-10 Zone-I

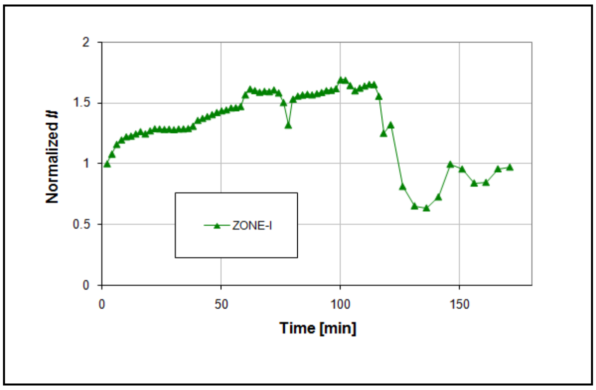

Figure 12: Normalized II evolution during 2nd Acid Stimulation at Awi 11-6

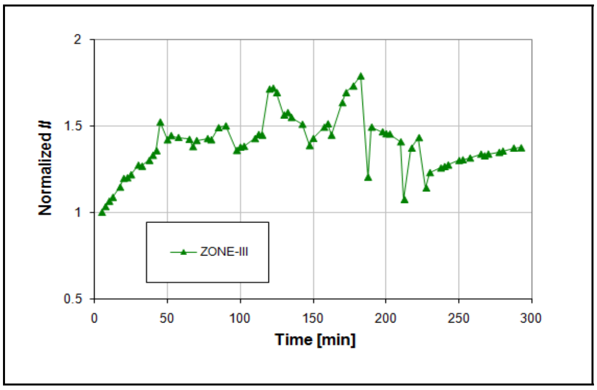

Figure 14: Normalized II evolution during Acid Stimulation at Awi 8-10 Zone-III

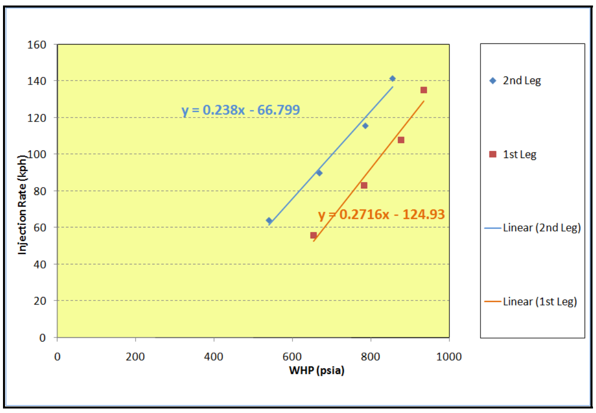

Figure 16: Initial Injectivity Test at both legs of Awi 20-1 conducted in Feb 2008 (Leg 1) and Mar 2008 (Leg 2)

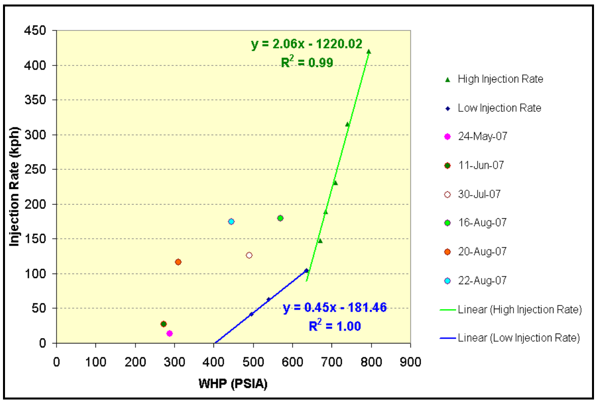

Figure 17: Injectivity Awi 18-1 after Phase-1 stimulation

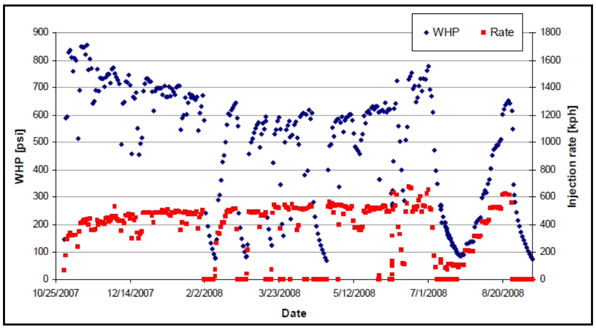

Figure 18: Injection history of Awi 18-1 during Phase 2 Stimulation

As can be seen in Figures 13 -15, the analysis is consistent with conventional evaluation results. The II trend at Awi 11-6RD indicates injectivity improvement during pre-flush and main acid treatment but impairment during the water flush. At Awi 8-10 wells the II trends indicate injectivity improvement after the stimulation.

5. HYDRAULIC STIMULATION

5.1 Project Background

Geophysical surveys such as magnetotelluric and time-domain electromagnetic surveys were done recently to find out new locations for injector replacement as part of the Salak injection realignment program, These surveys have identified potential reservoir extensions to the west of the proven production area (Cianten Caldera). Awi 18-1 and 20-1 wells that were drilled to delineate reservoir extension to The Cianten Caldera encountered low permeability. Based upon the completion test, injectivity of Awi 18-1 was found to be too low for a commercial injector (0.45 kph/psi). Figure 15 shows the results from injectivity index test conducted during the completion test in November 2006. It indicates that the well could take larger volume of water when injected with higher pressure.

The injectivity (index) is defined as

$$II = \frac{q_{inj}}{p_{wf} - p_r} = \frac{q_{inj}}{p_{wh} + \Delta p_h - \Delta p_f - p_r} \qquad (7)$$

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. 7** gives

$$q_{inj} = II\left(p_{wh} + \Delta p_h - \Delta p_f - p_r\right) \qquad (8)$$

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 645 psia on the wellhead.

Awi 20-1 was completed as a multilateral well. The 1st and 2nd legs were completed in Feb and Mar 2008 respectively. Completion tests revealed initially low injectivities on both legs (Figure 16).

Geothermal reservoir boundaries are somewhat vague. Therefore, new wells drilled in the region of reservoir boundary often encounter low or even zero permeability formations, such as Awi 18-1 and 20-1, and need to be stimulated to provide adequate rates. Drilling record and completion tests suggested that the wells had not suffered formation damage. Considering the success of injection hydraulic stimulation on Awi 11-5 and Awi 11-6, a long term water injection has been selected as stimulation method.

5.2 Injection Stimulation at Awi 18-1

The first phase of injection stimulation took place from May 8 to August 8, 2007. This phase included several water injection methods, by using gravitational force from main condensate pumps with injection rate up to 3.25 bpm (68 kph), a 'Peerless' pump with maximum rate of 1.4 bpm (30 kph) and finally with a higher capacity positive displacement pump with maximum rate of 6.7 bpm (140 kph.). The chronicled records of injection data are shown in Figure 17 along with the initial injectivity curves. Those measurements show lower WHP than those from pre-stimulation, which indicates the conductivity improvements of existing fractures and/or newly development of fractures around the wellbore.

Given the success of injectivity improvement by the first phase water injection, the second phase of injection was started on Oct 31 2007 using triplex pumps. With these, injection rate can be increased up to 26 bpm (543 kph) while maintaining WHP below its safe limit (1000 psi). Injectate was condensate water from power plant and its temperature at the wellhead was 90 – 100 ^oF. 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. The injection was stopped on Aug 26, 2008. Figure 18 shows the whole history of the injection rate and WHP over the second phase injection stimulation period.

From this Figure 18, we can observe that the WHP decreased 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 and they become steady in later period. To further understand the injection behavior, we define the injection efficiency as

$$I_{eff} = \frac{q_{inj}}{p_{wh}} \tag{9}$$

where p_{wh} is the wellhead pressure. The histories of wellhead pressure and cumulative injected mass are plotted in Figure 19. To filter these transient effects from temporal well shut-ins, the data are categorized into two groups: 1) the data recorded with WHP higher than 600 psi, and 2) the data with WHP lower than 600 psi. The filtered data (WHP < 600 psi) shows a clear increasing trend. Figure 20 shows the semi-log plot of the filtered data. The injection efficiency data seem to follow the power curve in the plot. From the semi-log plot, we can conclude that the injectivity improved during the water injection period.

A final injectivity test was conducted before the stimulation ended. Compared with the initial injectivity index (Figure 21), it improved by 180%. However, injection capacity has improved up to tenfold. This suggests that injection stimulation has not only improved permeability but has also established a connection between Awi 18-1 well and a low pressure system. Connectivity to the main Salak reservoir is undesirable since injection realignment program requires outfield injection. A micro earthquake (MEQ) was monitored during injection stimulation to identify propagation direction (Wibowo *et al*, 2008). It is known that injection tends to induce most of the MEQ activities observed in the field and also that shearing of existing fractures results in MEQ events. MEQ activity during injection stimulation is shown in Figure 22 and a side view is depicted in Figure 23. Significant numbers of induced MEQ events (around 220) were observed around the Cianten Caldera during injection stimulation, especially during phase-2. Interestingly, the MEQ trends go downward. This is an indicative of the fracture growth in this direction. The MEQ data also suggest a reduced likelihood of injectate from Awi 18-1 returning to the main production reservoir.

5.2 Injection Stimulation at Awi 20-1

Stimulation at Awi 20-1 used the same pumping units used for the Awi 18-1 stimulation. The stimulation campaign was started with a stepped rate injectivity test. This was the first injection test at Awi 20-1 as a multilateral well. Previous tests were done on the individual legs while the other leg either did not yet exist or was being isolated. The step-up rate injectivity test reveals the pre-stimulated II of 0.79 kph/psi. A PFO test took place after the injectivity test. The first period of injection stimulation was carried out from Oct 27 to Nov 30, 2008 by continuously pumping condensate water at the maximum rate.

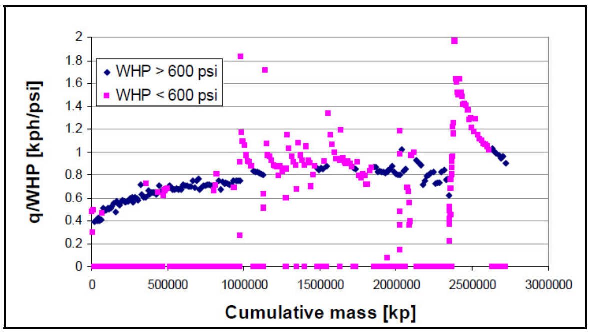

Figure 19: The histories of injection efficiency and cumulative mass injected from Awi 18-1.

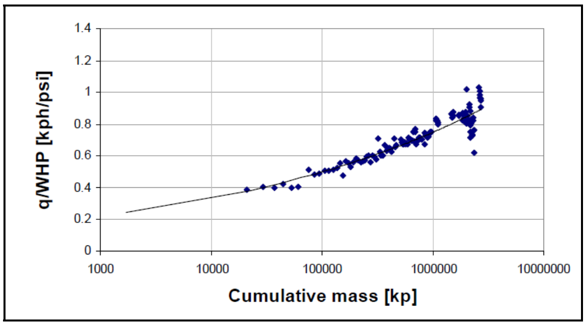

Figure 20: Semi-log plot of injection efficiency with WHP at Awi 18-1

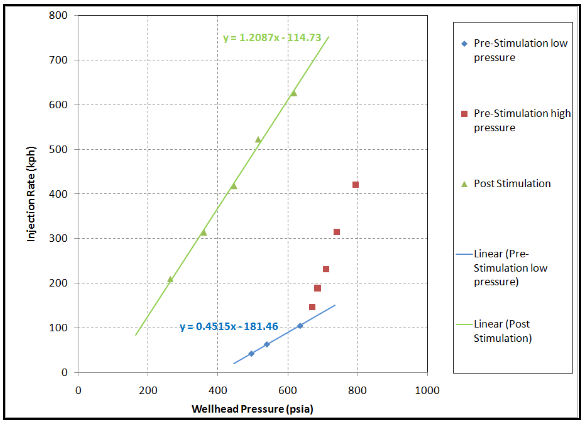

Figure 21: II values of Awi 18-1 before and after stimulation

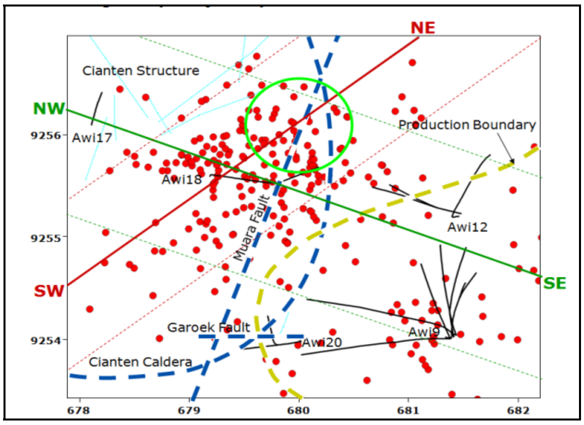

Figure 22: MEQ activity – Plane View (Wibowo, 2008)

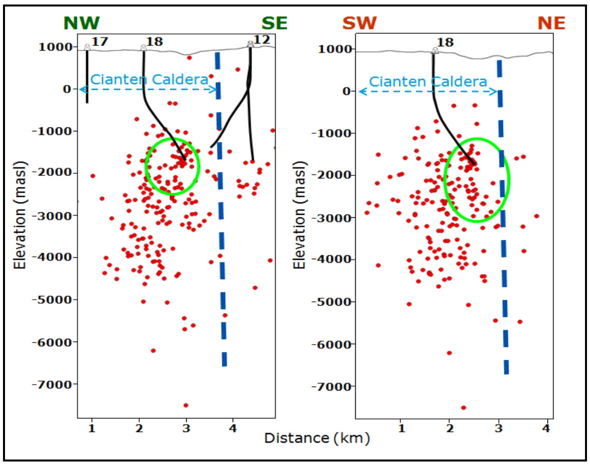

Figure 23: MEQ activity – Side View (Wibowo, 2008)

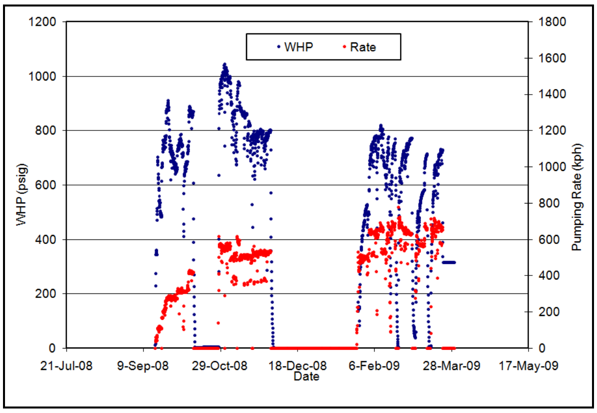

Figure 24: Injection history Awi 20-1 during injection stimulation

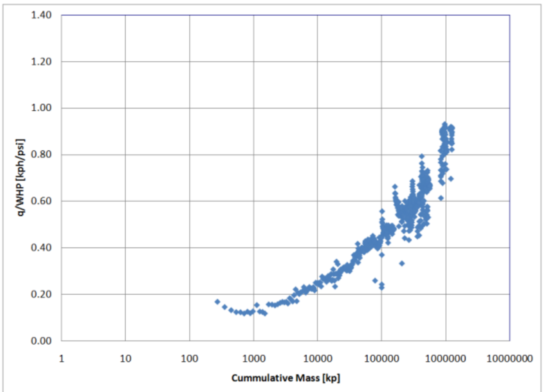

Figure 25: Semi-log plot of injection efficiency with WHP at Awi 20-1

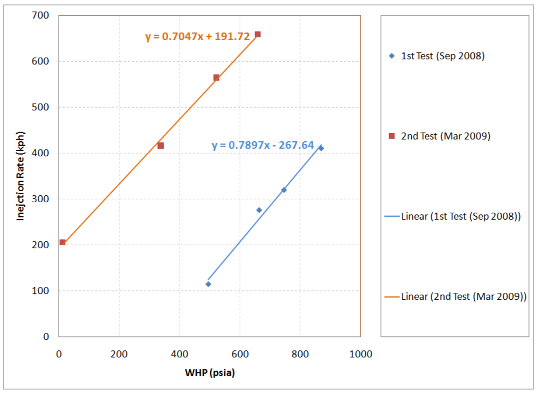

Figure 26: Injectivity Test Awi 20-1 as multilateral well, before and after injection stimulation

Figure 24 shows that the WHP declined at rate of 11.5 psi/day for the first 20 days of operation, which indicates a big enhancement of injection capacity. Injection stimulation was then halted due to contract renewal process for the pumps. During the second injection stimulation period, a cycling-pressure type of injection stimulation was applied. The First cycle involved pumping at the maximum rate for 25 days and then putting the well under shut in conditions for 1 day. The pumping period was then decreased to 7 days for the next three cycles. Injection was stopped on Mar 31, 2009. Following 65 days of cycled injection stimulation, the WHP of Awi 20-1 (under 30 BPM of condensate water injection) decreased by 140 psi at a decline rate of 3 psi/day. This decline rate is less than that obtained from continuous operation at the maximum rate. Overall, the WHP decline throughout the stimulation campaign was 370 psi, which indicates an injectivity improvement of the Awi 20-1 well. A different way to view the injectivity improvement is shown by the plot of injection efficiency as a function of cumulative injected mass (Figure 25).

A final injectivity test was conducted on Mar 2009, right before the stimulation was ended. As shown in Figure 26, the injectivity index did not improve after stimulation. This is an indication that improvement of injection performance at Awi 20-1 was mostly due to connectivity establishment between this well to a lower pressure fracture network (lower p_r on equation 8) rather than permeability improvement of existing fracture. Early evaluation of the observed induced MEQ events throughout stimulation period indicated connection establishment between Awi 20-1 with the proven Salak reservoir. Based on a pressure-temperature survey done in 2008, formation pressure at Cianten Caldera is 450 – 600 psi higher than that of the Salak reservoir. A tracer test is being conducted at Awi 18-1 and 20-1 to confirm preliminary conclusion from MEQ data about well connectivity to the proven Salak reservoir.

5. SUMMARY AND CONCLUSSIONS

Stimulation histories in the Salak Geothermal field reveal that natural fracture permeability in the geothermal system can be stimulated during water injection by thermal and hydraulic forces to open new and existing cracks. Improvement in permeability results in enhancement of injection capacity of the treated wells. Enhanced injection performance of new wells drilled at regions of the proven reservoir boundary may also be achieved by establishing its connectivity to the main reservoir with a lower pressure gradient. This argument is based on the unimproved injectivity index of Awi 20-1 well after injection stimulation. Bullheading high volumes of acidic fluid with pH of 3 – 4 to improve natural permeability is unproven. Insufficiently high concentration and poor acid placement control are probably the causes of the failure of this method.

Application of coiled tubing acid stimulation in Salak field has been fully successful to recover permeability and production performance of newly drilled wells that had suffered formation damage. Accurate well characterization and appropriate stimulation design are the most important keys to success. There is correlation between acid concentration, volume load and permeability improvement. However, the 2nd acid treatment at Awi 11-6RD suggests that doubling acid volume by repeating the treatment cannot provide additional permeability improvement. Further work is needed to identify the optimum acid concentration and load on individual treated wells, especially during acid treatment. This work becomes more feasible if we apply the real-time acid treatment evaluation. Consistent results between real-time evaluations with conventional evaluation methods support its future application.

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APPENDIX A

Downhole pressure measurement during acid treatment is often not feasible. Therefore, we need to convert tubing head pressure data into bottomhole pressure by considering the hydrostatic head and frictional pressure loss. As accelerational pressure loss is negligible, the relationship between the tubing head and the bottomhole pressure can be written as

$$p_{wf} = p_{th} + \Delta p_h - \Delta p_f \qquad \text{(A-1)}$$

The hydrostatic head is calculated as

$$\Delta p_h = g \int_0^H \rho dz \qquad \text{(A-2)}$$

In field units,

$$\Delta p_h = \frac{1}{144} \int_0^H \rho dz \qquad \text{(A-3)}$$

where Δp_h is in psi, H is in ft, and ρ is in lb/ft^3.

Frictional pressure loss can be written with the Fanning friction factor as

$$\Delta p_f = \frac{2 f \rho v^2}{D} L \qquad \text{(A-4)}$$

where f is the fanning friction factor and defined as

$$f = \frac{2\tau_w}{\rho v^2} \qquad \text{(A-5)}$$

where τ_w is the shear stress at the pipe wall. For laminar flow, it can be solved analytically by applying boundary layer approximation as

$$f = \frac{16}{\mathrm{Re}} \qquad \text{(A-6)}$$

where Re is the Reynolds number and is defined as

$$\mathrm{Re} = \frac{\rho v D}{\mu} \qquad \text{(A-7)}$$

In the most applications, flow regime in pipe is turbulent and friction factor is obtained experimentally. The Moody frictional chart is the most commonly used and also equivalent explicit equation is available as (Economides et al., 1993)

$$\frac{1}{\sqrt{f}} = -4 \log\left[\frac{\varepsilon}{3.7065} - \frac{5.0452}{\mathrm{Re}} \log\left\{ \frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{\mathrm{Re}} \right)^{0.8981} \right\} \right] \qquad \text{(A-8)}$$