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Determination of Optimum Injection Capacity using Pressure Transient Analysis

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ABSTRACT

Geothermal systems were divided into two classification based on its fluid, liquid dominated system and steam dominated system. Most of geothermal fields in Indonesia are liquid dominated, for example Dieng, Awibengkok-Salak, Lahendong, Ulubelu, Sibayak, and Sarulla (Saptadji, 2018). Developing a liquid dominated field had some impediments in locating injection wells. Pertamina had faced injection well problem in Tompaso Field when they had to decide whether to drill injection or production well (Hastriansyah, 2015). Hastriansyah (2015) used Nodal analysis to evaluate single well injection capacity. However, having more than two injection wells in the same cluster throws a new issue. Nodal evaluation did not evaluate inter well connection. It was questioned how much injection water that reservoir could accept. Would it be the sum of single well injection capacity or less. To answer the questions an interference test should be managed. The data have mainly been obtained by running periodic downhole pressure/temperature survey. Pressure Transient analysis was conducted to model well connectivity. Then, optimum injection capacity was determined by restricting bottom hole pressure at certain value for certain injection period in model.

1. INTRODUCTION

During development phase of a 110MW steam-field in Sumatera, injection wells were planned to be located at the outside of reservoir boundary. This was due to previous experiences of rapid injection breakthrough occurred in other fields in Sumatera. However, this strategy has its own main challenge that is the low permeability of formations outside the reservoir boundary. Geoscience evaluations showed that some geological features might be capable to act as flow conduits and thus two drilling pad locations was decided.

In well pad P, on the first drilling campaign, two wells were drilled onto which step rate and fall off injection tests were conducted. The results showed medium injection capacities for each wells. Another campaign was then commenced in order to fulfill the required injection capacity. However, geological data from the wells showed, among others, a permeability system associated with a fractured pyroclastic tuff layer. Due to the nature of its permeability characteristics, that is almost similar to a porous-medium, a concern grew regarding a rapid fluid saturation that might occur in such formation. In that case, the combined actual injection capacity of those wells (when injected simultaneously) would be lower than their individually calculated numbers.

An investigation then conducted by the means of simultaneous injection test and inter-well pressure interference test. Data from those tests was then analyzed and modelled in order to estimate the optimum injection capacity of those wells.

2. INJECTION WELL

By design, the new liquid dominated field is prepared to provide the power plant with steam equivalent to 110 MW of electricity. Injection wells were prepared to cover around 3600 t/h of brine and condensate. Geoscience and Reservoir Engineering studies resulted in a plan of splitting the location of injection wells into two well pads, both situated in specific locations that would enable the injection fluid to flow away from the production zone. In the first well pad, pad P, four wells were drilled in two separated campaigns.

All well drilled in cluster P failed to hit a TLC zone. Hydraulic fracturing was conducted to enhance well permeability by pumping water gradually from 0.7 bpm to 30 bpm into wellbore for 45-100 hrs. Injectivity index increase up to 40% after hydraulic fracturing. Originally, 6 wells were planned to be drilled in cluster P. After well P4 was drilled, drilling rig was moved to give us time to evaluate injection well capacity.

2.1. Permeability Characterization from Fall Off Test Data

Well completion test sequence included fall off test for each well after hydraulic fracturing job. Datasets were then evaluated using commercial Software Saphir to obtain reservoir properties such as permeability-thickness and skin. Type curve matching regression was conducted to datasets from P1, P2, and P3. P4 data set could not be analyzed due to recording error. Transient models providing reasonable match was obtained for each well, shown in Figure 2, giving well parameters as shown in Table 2.

Table 1 : Reservoir Properties and PVT Input for Pressure Transient Analysis

Properties	Value
Reference Phase	Water
Well Radius	10 in
Pay Zone	400 m
Viscosity	0.89 cp
Total Compressibility	4.35e-10 Pa^{-1}

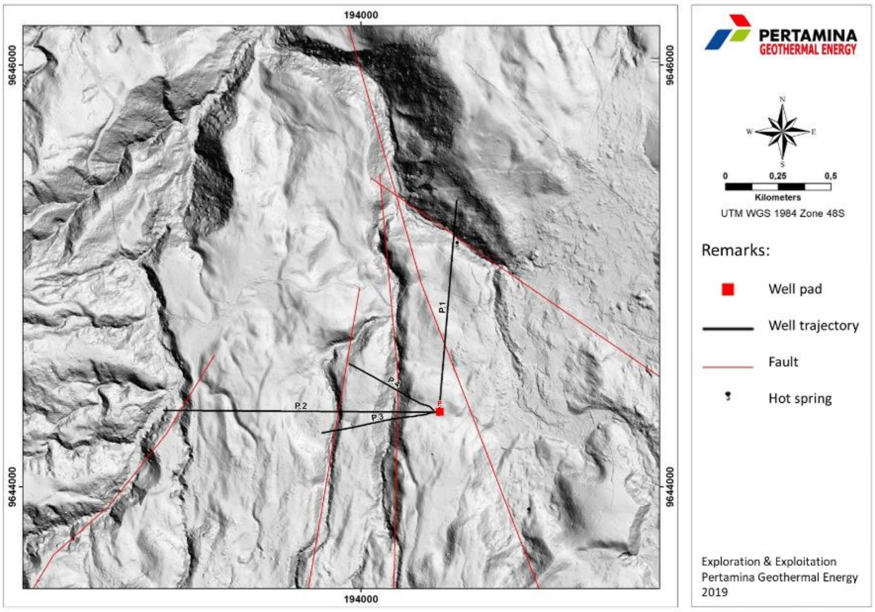

Figure 1 : Injection Well Map

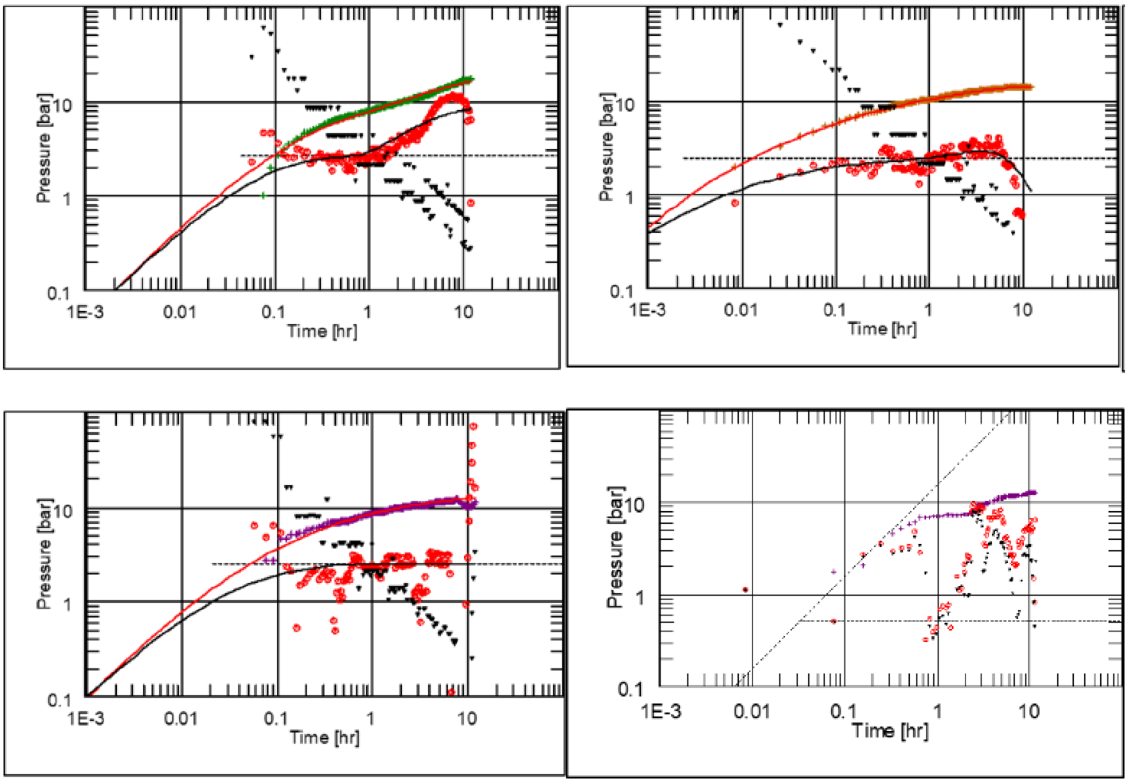

Figure 2 Type Curve Matching Fall Off Test P1, P2, P3, and P4 (in subsequent order)

Table 2 : Pressure Transient Result for Each Wells

Parameter	P1	P2	P3
Well Model	Vertical		
Reservoir Model	Homogenous		
Pi	173.4 bara	111.11 bara	98.7 bara
kh	14.7 D-m	22.1 D-m	20.9 D-m
k	36.7 mD	55.25 mD	52.25 mD
skin	-4.05	-3.85	-4.26

2.2. Injection Capacity

Individual injection capacities were calculated using Nodal Analysis (Hastriansyah, 2015) based on step rate injection test data. Several assumptions were applied, including single feedzone model, brine temperature of 40°C, and zero injection pressure (injection water level at surface).

Another injection test was conducted for P1, P2, and P3, this time with higher mass rate in order to confirm the step rate based capacities. From the test, P1 showed much lower injection capacity compared to its calculated capacity. Unfortunately, tests for P2 and P3 was inconclusive due to pump rate limitation.

Table 3 : Injection Capacity Calculation

Well	Injectivity Index (lpm/ksc)	Calculated Injection Capacity @ WHP = 0 bar (tph)	Actual Injection Capacity @ WHP = 0 bar (tph)
P1	327	689	140
P2	318.37	600	> 400
P3	305.55	510	> 400
P4	361.9	632	-

The result from P1 was nevertheless concerning, raising doubts about the calculated injection capacity values. In addition, having a layer of pyroclastic tuff acting as the main injection zone for all four wells, concerns ensued regarding the permeability system. The main concern was that such formation might allow significant pressure interference among wells, due to being relatively homogenous. The interference might later result in a rise of reservoir pressure the formation, thus reducing the injection capacity (more so when all wells injected simultaneously).

3. INTERFERENCE TEST

Following the issue of pressure interference, a test was conducted for the wells in pad P. Feedzone pressure of well P4 was continuously measured while well P2 was injected with brine of varying rate (300-400 t/h). The objective of the test was to characterize the communication between the two wells by analyzing the pressure response data. Figure 5 (left) shows well P4 pressure response profile measured at 1410mMD (static pressure previously measured was 101.5 barg).

Single downhole pressure measurement was also conducted on well P3, showing an average increase of 6 bar (compared to static pressure) throughout the depths confirming good communication between the wells. The pressure increase was also observable on the surface gauge (WHP), showing 0.3 – 0.6 barg (static WHP is 0 barg) during the test.

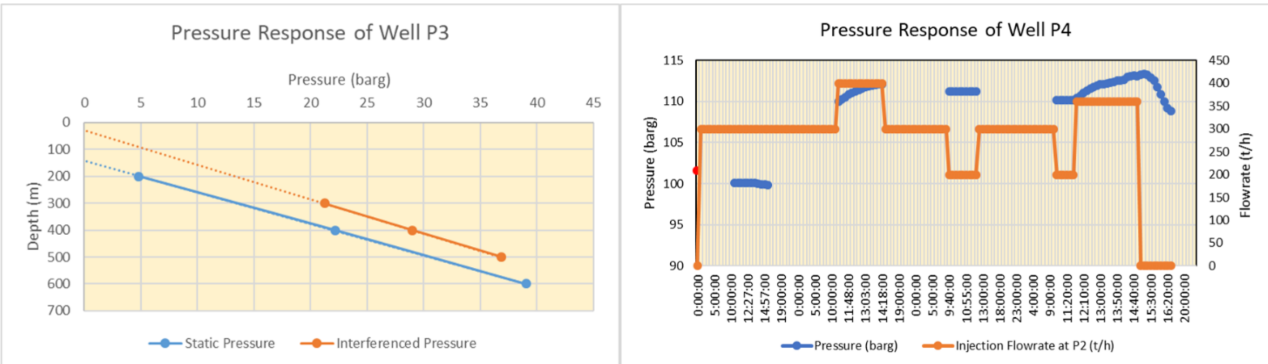

Figure 3: Pressure response during interference test from Well P2 as injection source.

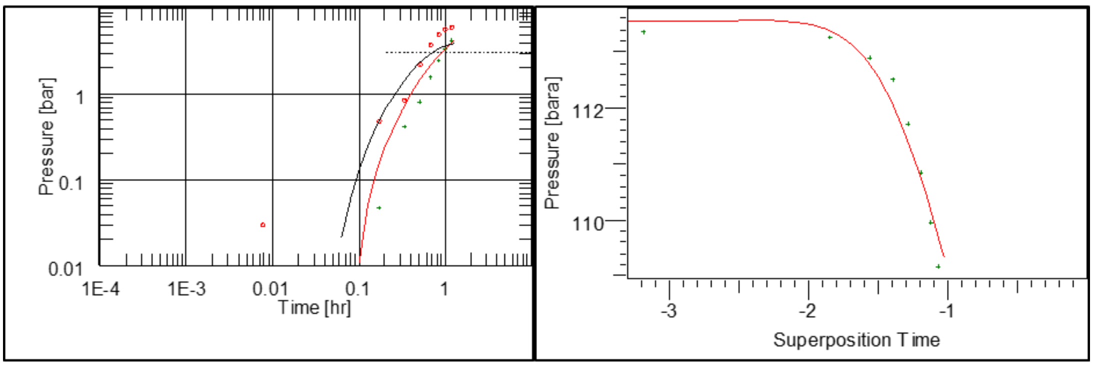

Figure 4 Type Curve Matching and Semi Log Plot Matching of Interference Test

3.1. Pressure Transient Analysis

Pressure Fall Off data from the interference test was analyzed, ultimately to obtain *kh* value characterizing the communication between the two wells. The result (shown in Table 4) would later be used as input in the injection simulation. The skin parameter was not computed from the interference analysis because the near wellbore region was negligible in the test.

Table 4 : Interference Test Result

Parameter	P2 - P4
Well Model	Vertical
Reservoir Model	Homogenous - infinite
Pi, bar	101
kh, D-m	23.3
k, mD	58
Porosity	0.06

4. INJECTION SIMULATION

The ultimate objective of the study was to obtain optimum individual injection rates for each well that, when combined, offers maximum injection rate. Injection simulation was required to achieve such objective, with communications between wells being adequately defined. *kh* values obtained from previous tests was to be used to characterize those communications. Individual well skin values, however, considered to be inaccurate. Individual well injection simulations were then performed, using actual injection data, to approximate new skin values with assumed temperature of 25°C

4.1. Individual Well Simulation

Simple 2D model was built to simulate the reservoir at major feed zone elevation. Wells were placed based on their respective feedzone locations. The grid was built incorporating Voronoi structure. Reservoir boundary used constant pressure respecting the vast area of the reservoir, while permeability input values was based on previous pressure transient analysis. The permeability was taken as the input in the well model then the distribution across the grid was calculated automatically using a linear regression.

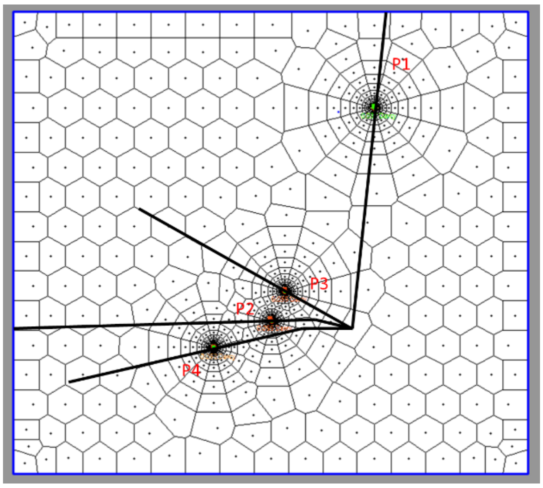

Figure 5 : Reservoir Grid

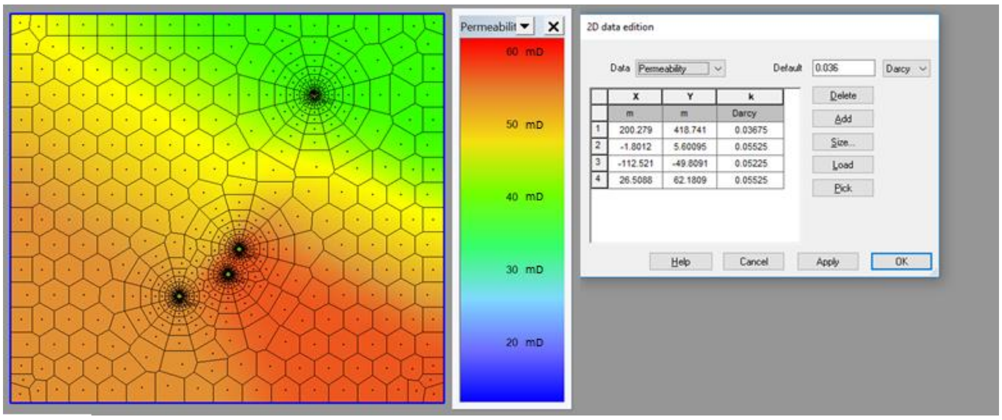

Figure 6: Permeability Distribution

The simulation was performed by replicating the previous actual tests. Constraining the maximum downhole pressure to 132.3 bara to emulate zero injection WHP (feedzone depth 1361 m TVD), skin value was then iterated. Table 6 shows skin values for each well as the result. These new skin values would then be used as inputs for the next simulation.

Table 5 : Skin Adjustment

Well	Skin from Fall Off Test	Adjusted Skin as an input to Simulation
P1	-4.05	4
P2	-3.85	-4.1
P3	-4.26	-4
P4	-	-4.7

4.2. Multi Well Simulation

The last process was then to obtain each well optimum injection rates that give maximum combined injection capacity. The process was iterative, performed by setting injection rates for each well and simulating the pressure response. Initial reservoir pressure was set at 101 bara. Maximum bottom hole pressure was restricted to 132.3 bara assuming water level at surface while the period of injection was 30 days. Having four wells available for injection in pad P, injection scenarios were then prepared utilizing all wells. Sensitivity of the optimum number of the injection wells was not included in this process.

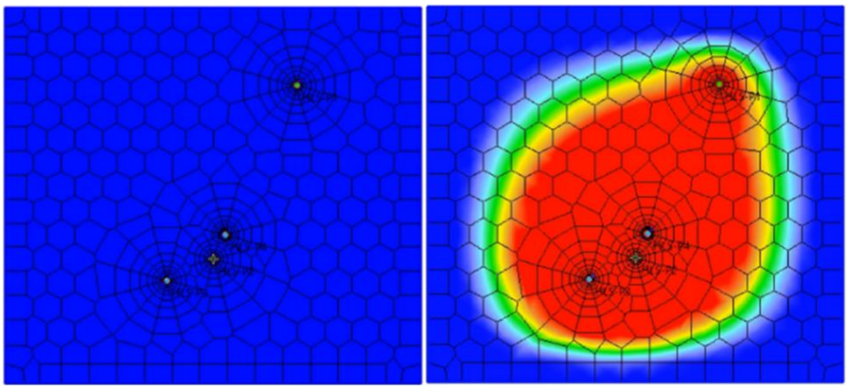

Figure 7: Reservoir Pressure Profile at t = 0 days and t = 30 days

Based on multi well model, total injection capacity in cluster P was 994 tph, lower than calculated single well injection capacity. It successfully modeled interference between well in reservoir. Table 7 shows optimum injection rates for each well as a result of the process.

Table 6 : Calculated Optimum Injection Capacity

Well	Multi Well Injection Rate (tph)	Incapa Injection Rate (tph)	Differences (tph)
P1	125	689	-564
P2	268	600	-332
P3	268	510	-242
P4	333	632	-299
Total	994	2431	-1437

5. DISCUSSION

The advantage of this interference test gives us more information about reservoir between source well and monitor well especially in overall injection capacity. Due to the interference effect, the total injection capacity in the reservoir is much lower compared to the individual well performance. A simulation has been successfully performed to capture the optimum injection capacity in the reservoir. With multi well injection rate dropped to 50% due to well interference, another injection well should be drilled in different cluster.

In this study, the non-isothermal effect is negligible in the software. For more complex geothermal system, numerical simulation emerges as the more powerful tool for PTA (Zarrouk & McLean, 2019). Nevertheless, based on these limitations, analytical transient result is relatively close and reasonable with error ranged from 6-30% based on previous study from Malibiran & Zarrouk (2014) and McLean & Zarrouk (2017). In this case, PTA model for cluster P is sufficient to evaluate injection capacity.

Apart from result from this study, actual injection metering should be considered in field operation for model validation.

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