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Comprehensive Tracer Testing in the Germencik Field

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ABSTRACT

Germencik Geothermal Field, which is one of the oldest high enthalpy geothermal fields in Turkey, is operational since 2009. As of 2017, two 47.4 MWe dual flash and four 22.5 MWe binary power plants have been constructed to exploit liquid dominated reservoir with feed zone temperatures as high as 234°C. In order to optimize re-injection a tracer test where three different naphthalene sulfonates tracers were simultaneously injected into three different re-injection wells, was conducted. Quantitative and qualitative analysis of tracer concentrations collected from 18 different production wells were used to identify connectivity between the re-injection and production wells. Three different tracer return curves were identified. It has been observed that flow velocity changed between 34.18 m/day to 3.12 m/day. The results showed that multi fracture model can be used to model tracer returns for most wells. However, flow – storage capacity plots showed that only a few wells produced from more than one fracture system.

1. INTRODUCTION

The Germencik geothermal area is located in western part of the Büyük Menderes graben in Western Turkey (Figure 1). Geological and geophysical studies conducted by General Directorate of Mineral Research and Exploration (MTA) in early 1970's indicated geothermal potential (Başkan, 1970; Yüksel, 1971; Keskin, 1972). The presence of high heat flux in the geothermal field was identified with fumaroles, hydrothermal alterations, hot water springs and shallow wells with hot water present in the area. Furthermore, the data obtained from young volcanic rocks, and water and gas analyses of hot springs indicated the presence of a magmatic intrusion in this region. As a result of geological investigations integrated with the application of new geochemical methods a drilling campaign started in 1980's by MTA. The first successful wells (ÖB-1 and ÖB-2) in the Ömerbeyli field indicated high enthalpy resource at two different layers: Miocene conglomerates (200 °C) at 975 meters and albite-gneiss and quartzite (231°C) at a depth of approximately 1000 meters (Şimşek, 1984). A total of 9 wells were drilled by MTA between 1982 and 1986 (Şimşek, 2012). After privatization of the field, Gurmat drilled more than 70 new wells. The results of these new wells showed that Germencik reservoir is liquid dominated, with feed zone temperatures as high as 234°C, whose main feature is the high non-condensable gas (mainly CO_2) content as much as 2.5% by weight (Türeyen et al, 2014). The field, which is operational since 2009 has two 47.4 MWe dual flash and four 22.5 MWe binary power plants.

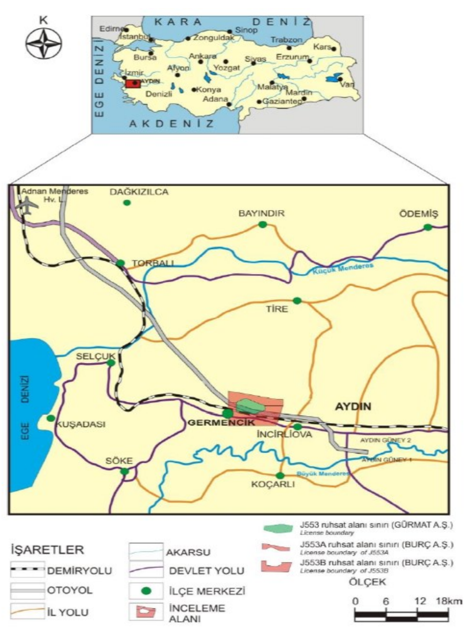

Figure 1: Location of the Germencik Geothermal Field (Şimşek, 2012)

Large scale reinjection is a key element of the resource management of the Germencik geothermal reservoir. The reinjection areas are developed based on dipole (Alangülü) in northern section and peripheral injection scheme for the rest of the field. Monitoring data collected since large-scale reinjection started at Germencik reservoir in late 2009 doesn't indicate any significant cooling of the production wells, but, since Germencik geothermal reservoir is not developed on regular well spacing, injection – production wells may exhibit weak or strong connectivity that in turn may result in premature cooling or subpar reservoir performance. Several reservoir studies were conducted using capacitance-resistance modelling (Akin, 2014), lumped parameter modelling (Türeyen et al, 2014; Türeyen et al, 2016) and numerical modeling (Veizades, 2017) approaches to predict reservoir performance.

A recently conducted tracer test where 3 naphtalene sulfonates were used, identified injection performance and connectivity of injection and production wells. The paper is divided into three main parts. First geology of the Germencik field is introduced. After the description of the tracer test, quantitative and qualitative analysis of tracer concentrations collected from different production wells are discussed. Paper is concluded using results obtained from analytical tracer models.

2. GEOLOGY OF THE FIELD

The Germencik geothermal area is located in the Menderes Graben along and south of the Menderes Massif (Figure 1). The Quaternary to Miocene-age sedimentary rocks that fill the graben are juxtaposed against the Paleozoic metamorphics of the Kızılcagedik Horst by the E-W trending, S-dipping, normal Ömerbeyli Fault (Şimşek, 2012) that forms the northern boundary of the field. There are synthetic conjugate faults and orthogonal cross faults within the field. Major faults in the field include E-W trending, S-dipping normal-listric faults that form the graben bounding faults and N-S cross cutting faults that cut the E-W trending faults. Secondary NE-SW faults are also present. The surface of the field is covered by Quaternary alluvium at a depth of 50 to 150 m over Pleistocene to Miocene-age volcanogenic sediments with a thickness of up to 1200 m or more thickening from the Ömerbeyli Fault in the north to the axis of the Menderes Graben in the south. Miocene aged and younger sedimentary rocks that unconformably overlie Paleozoic metamorphics become thinner from north to south. The Paleozoic metamorphic basement rocks that consist of interlayered schists and marbles are the primary reservoir rocks. Most geothermal fluid entry zones occur in the brittle marble, calcschist and quartzite zones within the reservoir rocks. There are two stratigraphically bound producing levels in Germencik reservoir (Şimşek, 2012):

1) The shallower reservoir is in conglomerate zone within the Vişneli formation between the depths of 250 and 1000 m below the surface, deepening to the south. This zone is approximately 200 to 250 m thick and the temperature is larger than 200 °C. It capped by a section of claystone and siltstone of the Arzula formation that gets thicker to the south.

2) A zone of marble, calcschist and quartzite within the Paleozic Menderes Metamorphic Basement forms the deeper reservoir. This zone has a temperature larger than 215 °C capped by relatively impermeable allocthonous gneiss that thins to the south. The permeability of this zone is mainly secondary due to fracturation of brittle marbles formed during the tectonic deformation which is still active (Simsek, 1984; Tekin and Akin, 2011)

Both feed zones are recharged with meteoric waters along faults and fracture zones. These waters are then heated at deeper reservoir sections and move up to the surface through the tectonic lines by convection. The produced geothermal waters are high enthalpy, meteoric origined and old (Filiz et al. 2000). Şimşek (2012) reported that the reservoir contains largely homogenous sodium-bicarbonate-chloride brine. Initial salinity of the reservoir fluid expressed in total dissolved solids is approximately 5000 mg/liter. Reservoir temperatures estimated from geothermometers for the Germencik geothermal resource are limited to silica geothermometers. The temperature estimates by chalcedony geothermometers change between 221 °C and 226 °C, which compare well with the measured feed zone temperature by dynamic PTS surveys.

3. TRACER TEST DESIGN AND IMPLEMENTATION

Three injection wells were selected to be used in tracer test based on their locations: OB-15A is located at the center of the license area where production wells are located; OB-30A is near the highest producing well, OB-14 and OB-32 is the well with largest amount of colder injectate well near EFE-3 and EFE-4 production wells (Figure 2). Naphthalene sulfonates have proven to be effective tracers in high temperature geothermal reservoirs as they are affordable, easily detectable with fluorescence spectroscopy, thermally stable and environmentally benign (Rose et al. 2001). Three different naphthalene sulfonates were injected from these wells. In each well naphthalene sulfonate was diluted with 3 tons of water and pumped in 4 hours. Table 1 gives the amounts of naphthalene sulfonates used in these wells. These amounts were selected based on a methodology described elsewhere (Akin et al, 2016). The test was conducted between 26.3.2016 and 23.10.2016. A total of 18 production wells were sampled 3 times a day during the tracer test using sampling ports and mini separators. Test continued without any interruption except for mechanical problems that were fixed usually less than 4 hours. The only major stop in some production wells occurred due to planned service of EFE-4 GPP at 114^{th} day of the test. Analyses of the samples collected from the production wells were carried out using an HPLC as described in Rose et al (2001).

Table 1. Naphtalene sulfonate type and amount used in injection wells.

Well	Tracer	Amount, kg
OB-15A	2.7 Naphtalene disulfonate	125
OB-30A	1.5 Naphtalene disulfonate	175
OB-32	2 Naphtalene dsulfonate	125

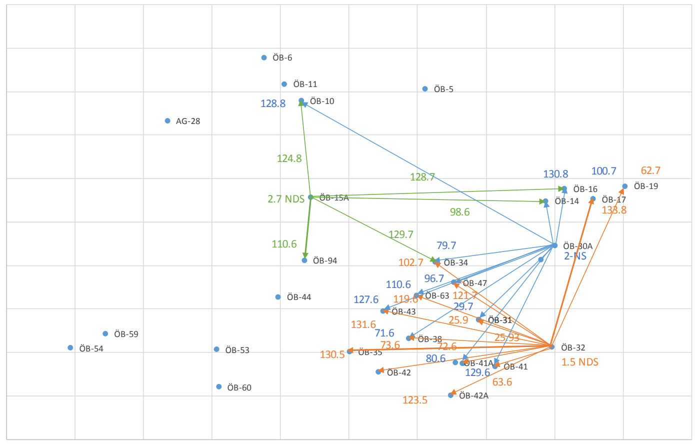

Figure 2: Mean arrival times and connectivity based on tracer return data.

4. RESULTS AND DISCUSSIONS

Injected naphthalene sulfonate tracers were observed in all sampled production wells. Mean arrival times obtained from the tracer return curves are given in Figure 2. When the tracer map is analyzed it has been observed that tracers followed aforementioned E-W trending, S-dipping normal-listric faults that form the graben bounding faults. Then the tracers used N-S cross cutting faults that cut the E-W trending faults. Finally, NE-SW faults were utilized as secondary flow paths. Three different tracer return curves were identified: 1) Fast tracer return curves due to high permeability and/or short injection/production well distance (Figure 3); 2) Slow increasing broader tracer return curves due to longer reservoir residence time (Figure 4); 3) Slowest increasing tracer return curves where mean tracer arrival times have not been reached during the test (Figure 5). Reservoir flow velocities were obtained based on the mean arrival times. It has been observed that flow velocity changed between 34.18 m/day to 3.12 m/day. It was observed that injection-production well pairs that are located on or near E-W trending fault zones have higher tracer velocities compared to ones that are on N-S or NE-SW fault zones. This conforms with graben forming tectonic deformation. These results are also in accord with those obtained with capacitance-resistance modelling (Akin, 2014). Average thermal velocities calculated (Shook, 2003) using tracer mean arrival times changed between 6 m/d to 7 m/d. But along E-W direction values as high as 18.33 m/d were obtained.

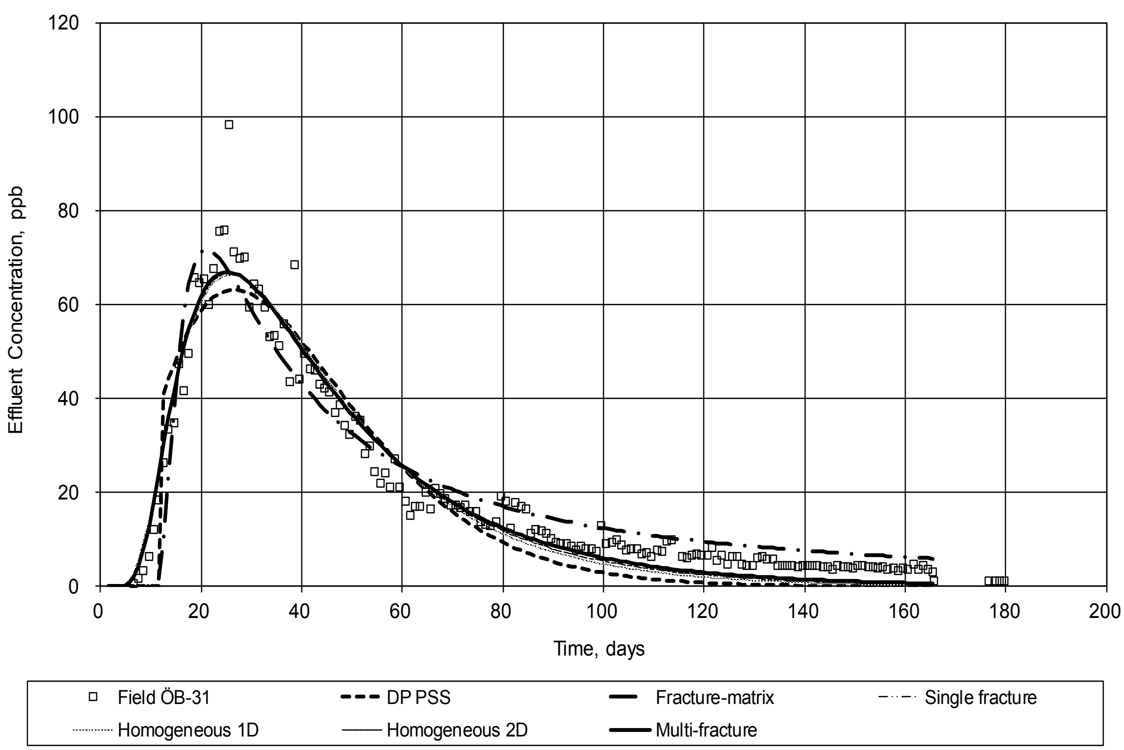

Figure 3: OB-31 1.5 NDS tracer return data.

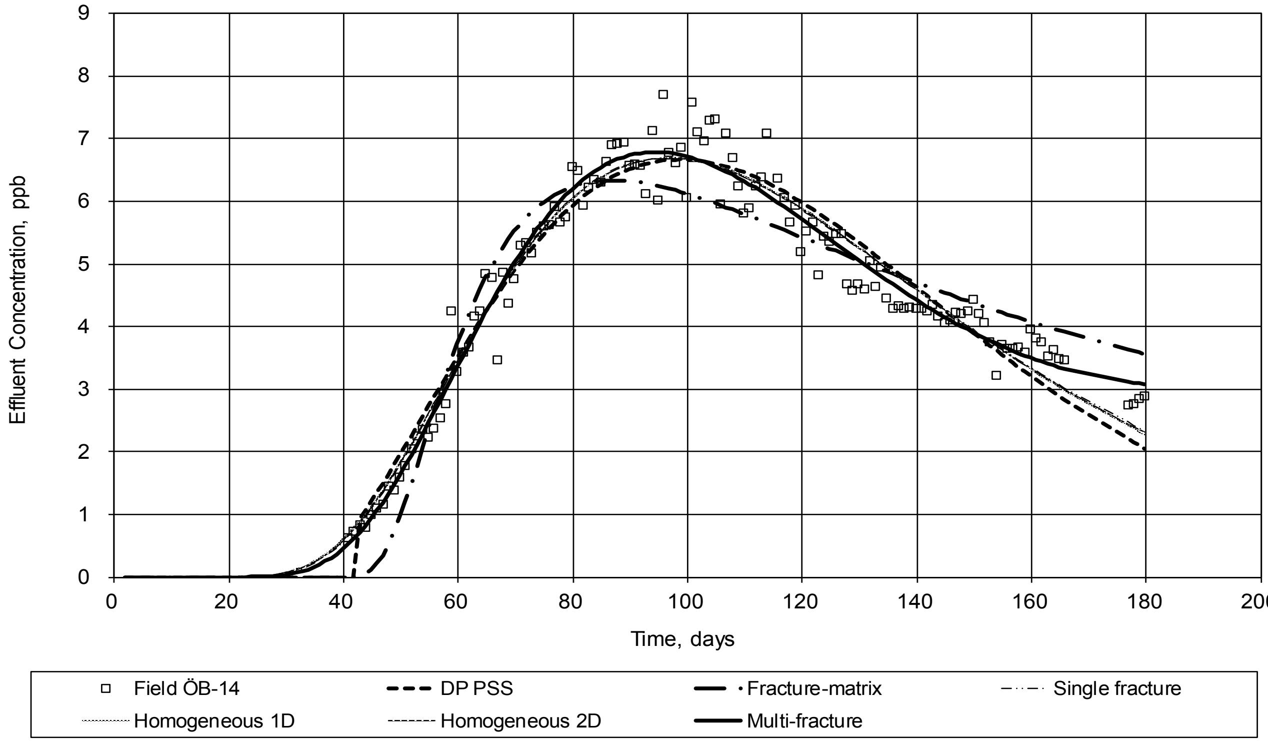

Figure 4: OB-14 2.7 NDS tracer return data.

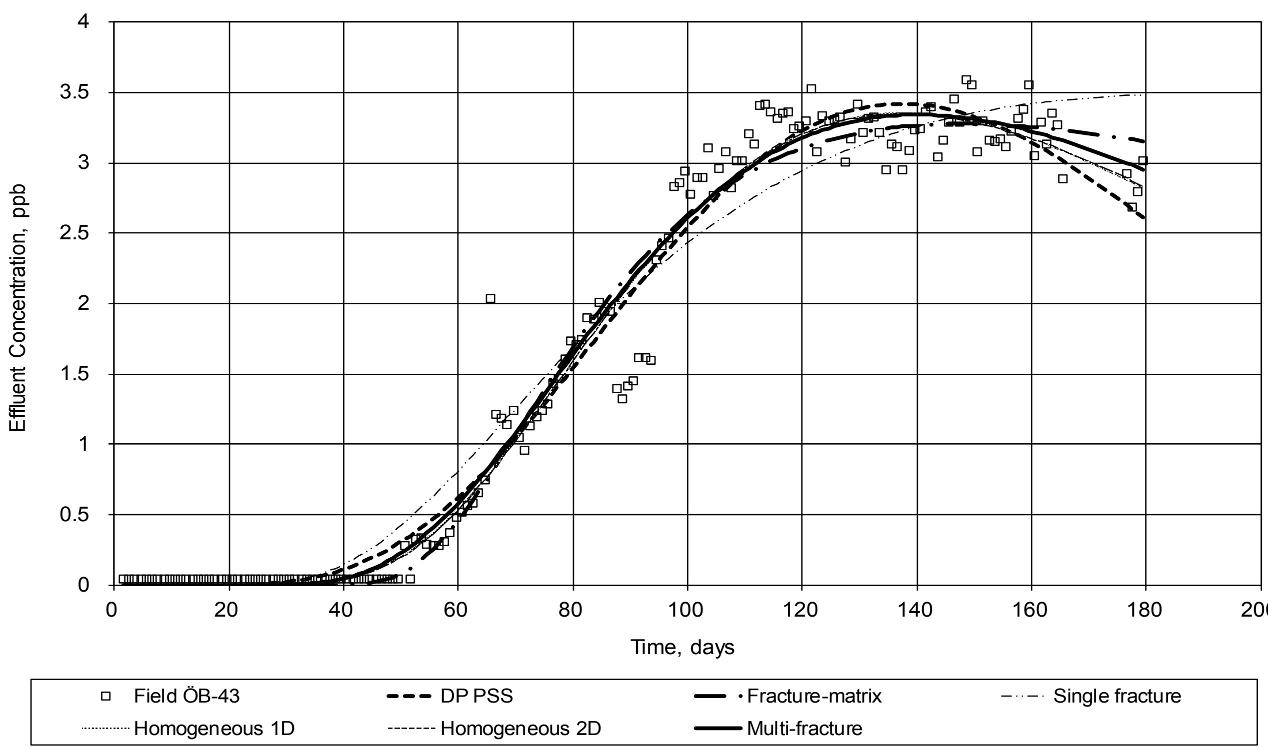

Figure 5: OB-43 2 NS tracer return data.

Single fracture model and its variant where 3 fractures were used matched the tracer returns better than the homogeneous, fracture - matrix and the double porosity pseudo steady state models (Figure 3 – 5). This simple fracture model (Fossum and Horne, 1982) was used to model the tracer return curves. The interpretation method was based on a fracture connecting respective feed-zones in the reinjection and production wells involved. The properties of each fracture, along with injection and production rates, determine the tracer recovery in the production well involved, with the properties being Peclet number, apparent length, mean arrival time, velocity and dispersion coefficient in each of these fractures. The results showed that three fracture model can be used to model tracer returns for most wells. The mean arrival time of tracer was usually small in the main fracture. It was concluded that the flow occurs in axial fracture axis since Peclet numbers change between 1.5 and 15 in the main fracture. It can be speculated that colder injectate fully mixes with hotter reservoir fluid in this fracture. Flow is slower and diffusive in secondary fractures. The flow contribution of these fractures are usually high (>%90) in most wells. Peclet number of these secondary fractures are smaller than 1.5. As a result, most of the injected waters enter these secondary slower fractures and then diffuse slowly. The temperature of these waters increase as they move along these fractures. These findings are in accord with insignificant temperature drop observed in the production wells.

Flow geometry was obtained using moment method suggested by Shook (2003). Flow – storage capacity plots showed that only a few wells showed heterogeneous behavior. In this regard, it has been observed that the area between OB-17 and OB-30A as well as OB-19 and OB-30A are more heterogeneous compared to rest of the field. In these wells 45% of flow is obtained from 10% of the storage capacity. Tracer recovery was obtained for each production well. Based on these recoveries it was concluded that reservoir volume is larger near OB-14 and OB-16 when compared with the rest of the field. OB-94, OB-38, OB-63 and OB-47 have also large reservoir volume (Figure 6 – 8). Derivative of flow – storage capacity plots showed that several wells (ÖB-14, ÖB-17, ÖB-19, ÖB-31, ÖB-38 and ÖB-41A) produced from more than one feed zone (hydraulic flow unit). These wells possibly tap both of the aforementioned feed zones. The rest of the wells produce from a single feed zone possibly deep – brittle marbles.

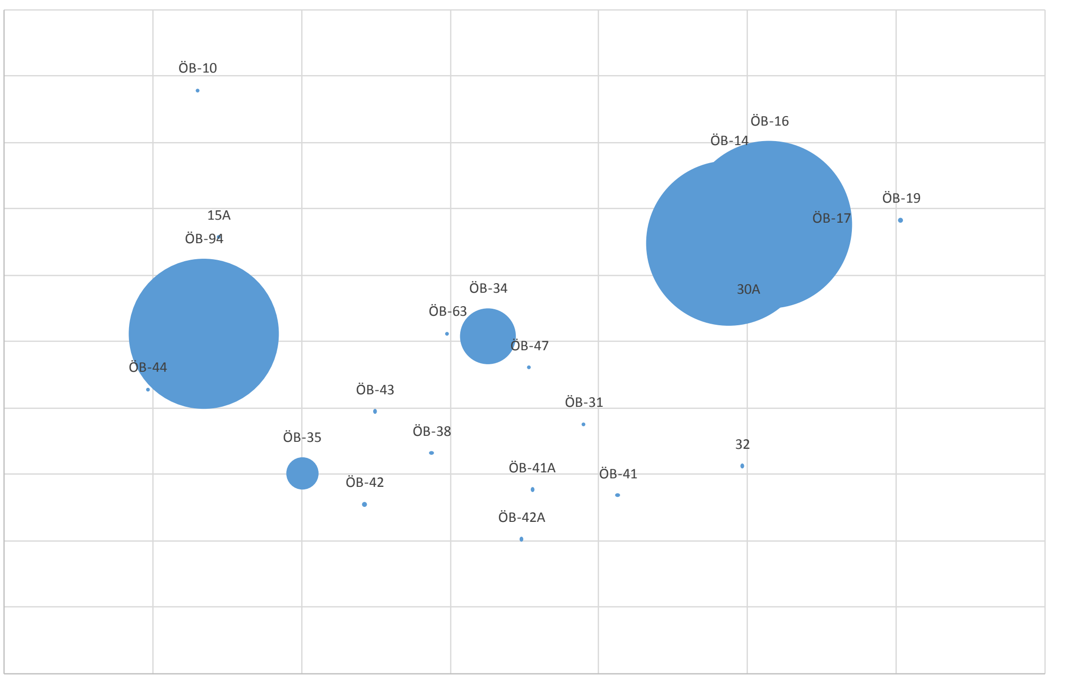

Figure 6: OB-15A tracer recovery.

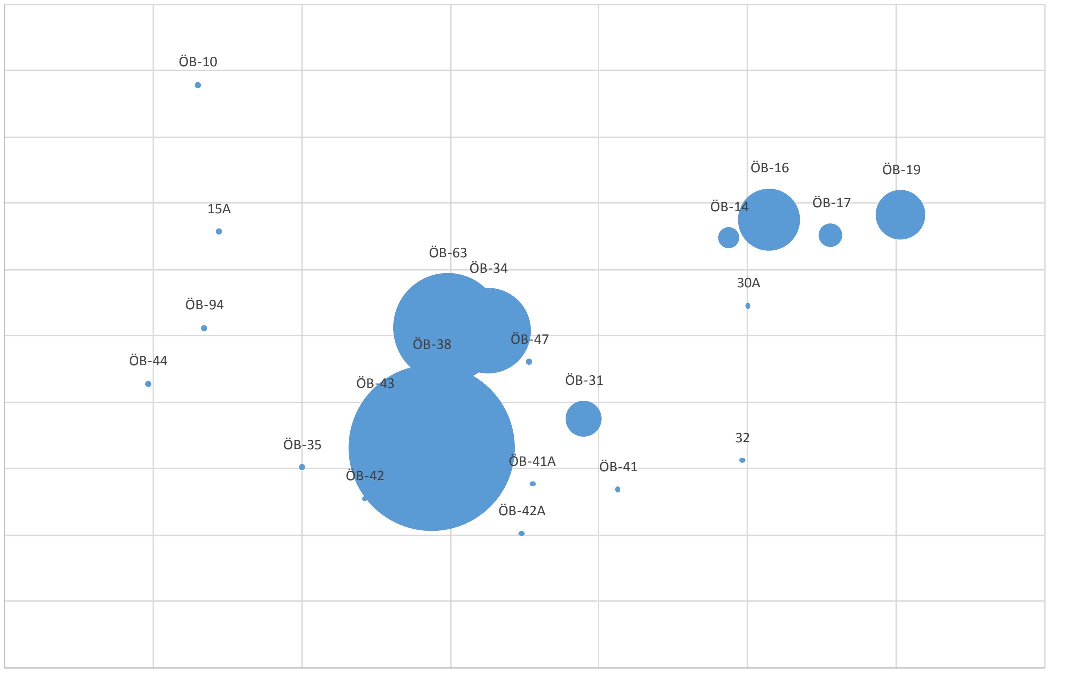

Figure 7: OB-30A tracer recovery.

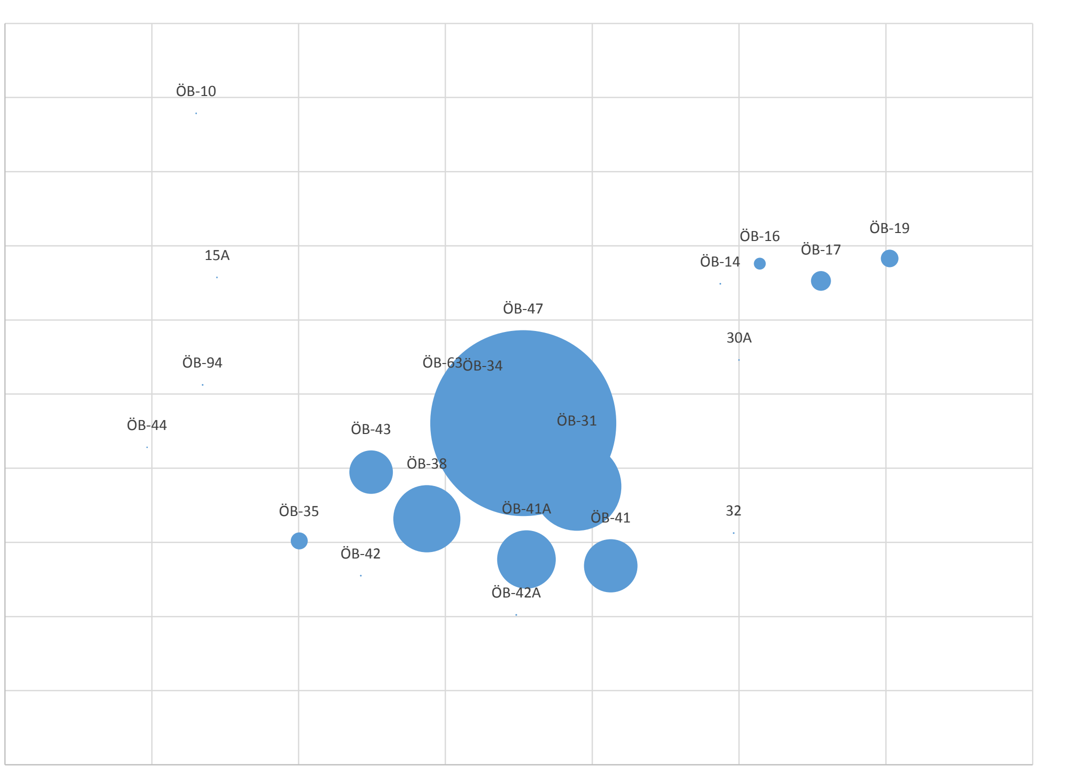

Figure 8: OB-32 tracer recovery.

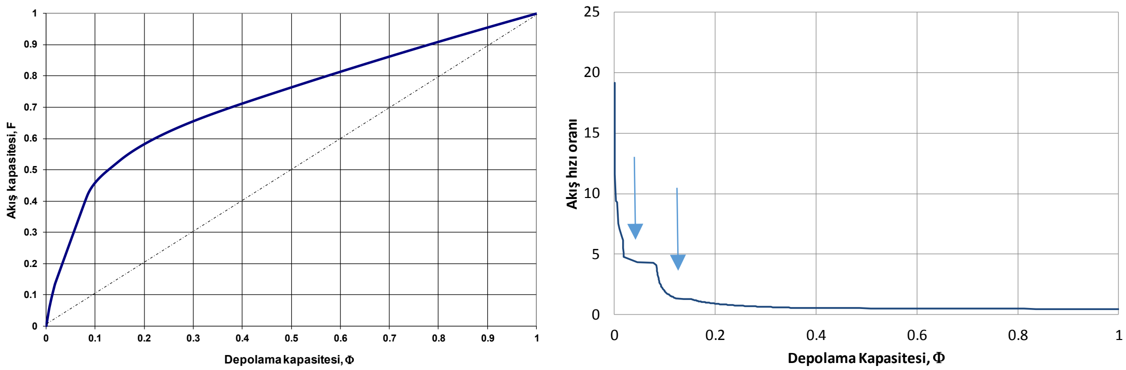

Figure 9: OB-17 flow – storage capacity (left) and velocity – storage capacity (right) plots.

5. CONCLUSIONS

A tracer test where three different naphthalene sulfonates tracers were simultaneously injected into three different re-injection wells, was conducted in Germencik geothermal reservoir. Quantitative and qualitative analysis of tracer concentrations showed that

1) Injection-production well pairs that are located on or near E-W trending fault zones have higher tracer velocities compared to ones that are on N-S or NE-SW fault zones.
2) Several wells such as OB-14 and OB-16 showed significant tracer recovery. Reservoir flow velocities up to 34.18 m/day were obtained for such wells.
3) The tracer recovery was successfully modelled by a simple model of fractures connecting feed-zones of reinjection and production wells.
4) The area between OB-17 and OB-30A as well as OB-19 and OB-30A are more heterogeneous compared to rest of the field.
5) Derivative of flow – storage capacity plots showed that several wells (ÖB-14, ÖB-17, ÖB-19, ÖB-31, ÖB-38 and ÖB-41A) produced from more than one feed zone. But the rest of the sampled wells produced from a single feed zone.

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