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Laboratory Study on Formation Damage in Geothermal Reservoirs Due to Fines Migration

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ABSTRACT

Here we present a new method to assess formation damage in geothermal reservoirs. It is long known that formation damage is caused by mobilisation, migration and straining of natural reservoir fines. Thus the laboratory methodology developed and presented here aims to determine the permeability decline from rock fragments. It includes: development of a composite porous medium consisting of borosilicate glass beads and sandstone fragments; mobilisation of fines from fragments by alternation of velocity and ionic strength of water flowing through this porous medium; identification of minerals in collected fines; calculation of the total potentials of interaction between fines and sandstone matrix and their effect on fines mobilisation and formation damage.

Velocity-induced fines migration is responsible for a non-significant reduction of rock permeability leading to initial formation damage. Following low-ionic strength water injection increases electrostatic repulsion force between clay particles and sand surface, further mobilizes particle resulting in formation damage. Mobilised fines with mixed-layer illite/chlorite mineralogy are responsible for rock permeability reduction due to pore-throats clogging.

Fines migration is one of the most widely spread physics mechanisms of formation damage in oil and gas wells. Numerous recent publications report well impairment by fines migration in geothermal fields. Estimation and prediction of well formation damage is carried out by evaluation of fines removal capacity and fines migration in rocks from the well for which cores and fragments are available. The proposed method is applied to assess possible formation damage in the geothermal reservoir using its rock fragments in the absence of cores. Appreciable residual permeabilities for studied rock fragments at ionic strength of reservoir water indicate that the studied geothermal well is probably capable of producing commercial quantities of geothermal fluids.

1. INTRODUCTION

Migration of fines in rocks leads to formation damage and productivity decline of geothermal wells. Rock permeability decline is caused by retention of mobilised particles through the following mechanisms: electrostatic attraction/attachment, straining, bridging and gravity sedimentation. Alteration of fluid flowrate (Mojarad and Settari 2008; Bradford, Torkzaban et al. 2011), pH and ionic strength of fluid (Chalk, Gooding et al. 2012), pore and particle size distributions (Aji, You et al. 2012; You, Badalyan et al. 2013), heterogeneity of pore space, surface chemistry of particles intensifies one particle retention mechanisms over others. When particles are larger than pore throats, straining is regarded as an important mechanism of particle deposition and consequent formation damage under unfavorable particle attachment conditions (Bradford, Simunek et al. 2006). Mobilisation of clay particles in geothermal reservoirs is regarded as an important mechanism leading to permeability decline according to (Rosenbrand, Fabricius et al. 2013a). High temperature has a detrimental effect on permeability of geothermal rocks due to mobilised particle agglomeration and the formation of bridges at the pore-throats (Rosenbrand, Fabricius et al. 2013b). According to Tchistiakov (Tchistiakov 2000), variation of physico-chemical conditions such as fluid ionic strength and pH may mobilize clay particles and cause formation damage even at relatively low fluid velocities.

Our previous studies (Badalyan, Carageorgos et al. 2013; Badalyan, Carageorgos et al. 2014) focused on the development of a new procedure for the assessment of the effect of fines migration on the formation damage in Salamander-1 geothermal well (Pretty Hill Sandstone Formation, Otway Basin, South Australia, Australia) for which core plugs are not available. A newly developed methodology allows estimation of permeability for rock fragment via the correlation between permeabilities for core plug and fragment from the same sample originated from another well but located in the same sandstone formation. Low-ionic strength-induced fines migration was determined as the main reason behind lower than expected well productivity for Salamander-1 geothermal well.

The Celsius- geothermal exploration well had been successfully completed in November 2011 and plugged with cement plugs to isolate aquifers according to (Geodynamics Limited 2014). This well is located in the Hutton Sandstone Formation of the Cooper/Eromanga Basin in South Australia. The depth of this well is 2,360 m according to (Richter 2014). In order to evaluate the performance of this well during water production stage, cores should be tested in the laboratory at various fluid flowrates and fluid chemistry conditions. Unavailability of cores from the Celsius-1 well exacerbated laboratory analysis for the evaluation of this well performance. Instead, only fragments from Celsius-1 well are available from the Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) Drill Core Storage Facility (CSF) of the Government of South Australia (Australia). The procedure for testing fragments and correlation of the obtained results with those for cores from wells located in the same formation has been developed earlier (Badalyan, Carageorgos et al. 2014), and is successfully applied for the characterization of rock fragments from Salamander-1 geothermal well. Cores from Strzelecki-17 well located in the same geological formation as Celsius-1 well are obtained from DMITRE. This well has been completed as an oil producer according to the well completion report (Delhi Petroleum Pty. Ltd. 1983). The thickness of the Hutton Sandstone formation for this well is 94.5 m starting from the depth of about

1672.7 m. Performance of Celsius-1 geothermal exploration well is predicted using the newly developed program described in details elsewhere (Badalyan, Carageorgos et al. 2013; Badalyan, Carageorgos et al. 2014).

2. MATERIALS

Sandstone core from Strzelecki-17 and sandstone fragments from Celsius-1 wells are obtained from The Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) Drill Core Storage Facility (CSF) of the Government of South Australia (Australia). The following core and fragments are chosen for the present study: Strz-17/c, Strz-17/f, Cls-1-1/f, Cls-1-2/f and Cls-1-3/f (where “c” stands for “core”, and “f” stands for “fragment”). Geometrical sizes for these samples together with their porosities measured using the imbibition method by saturating them with 0.6 M NaCl solution according to the procedure described in (Badalyan, Carageorgos et al. 2014) are presented in Table 1.

Sample Name	Core diameter, cm	Core length, cm	Porosity, %	Fragments volume,
Strz-17/c (1673.5 m)	3.792	4.130	14.4	N/A
Strz-17/f (1673.5 m)	N/A	N/A	13.7	7.226
Cls-1-1/f (2271-2274 m)	N/A	N/A	6.13	10.480
Cls-1-2/f (2280-2283 m)	N/A	N/A	5.39	10.211
Cls-1-3/f (2286-2289 m)	N/A	N/A	4.45	7.227

Table 1. Characterization of rock samples.

3. EXPERIMENTAL SETUP AND PROCEDURE

In comparison to our first study (cite here) a modified version of the experimental setup was used for the investigation of formation damage in geothermal reservoir and is shown in Figure 1.

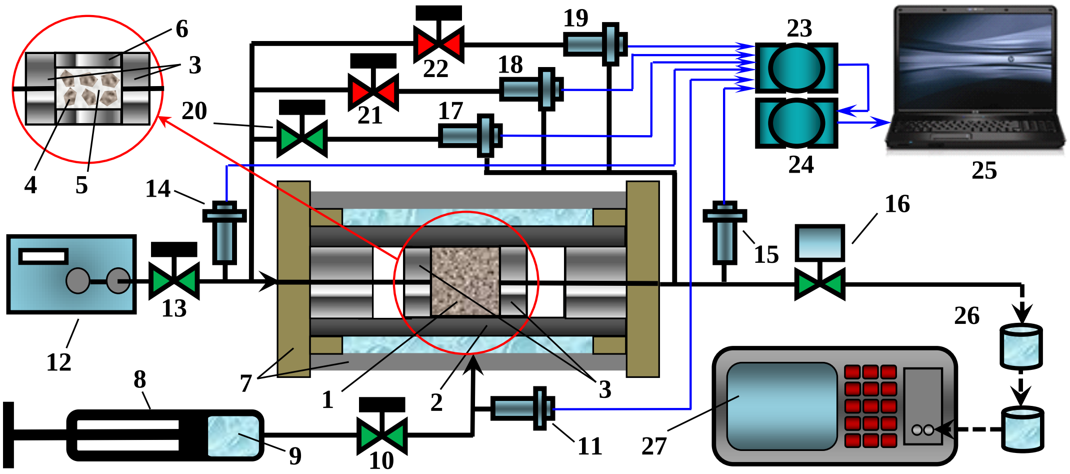

Figure 1: Setup for liquid permeability measurements and fines migration studies. 1 – rock core; 2 – Viton sleeve; 3 – stainless steel stoppers; 4 – rock fragments; 5 – glass beads; 6 – stainless steel cylinder; 7 – high-pressure coreholder; 8 – manual pressure generator; 9 – distilled water for overburden pressure; 10, 13, 20-22 – 2-way manual valves; 11, 14, 15 – pressure transmitters; 12 – HPLC pump; 17-19 – differential pressure transmitter; 16 – back pressure regulator; 23 – data acquisition module; 24 – signal conditioner; 25 – personal computer; 26 – beakers for effluent samples; 27 particle counter/sizer.

Formation damage is usually caused by mobilisation of fine particles due to high fluid velocities or low ionic strength of a flowing fluid. Therefore, the experimental program for the core and fragments consists of the following parts.

Formation damage at high fluid velocity. Core plug Strz-17/c was saturated with brine solution (0.6 M NaCl) and placed inside the core-holder. An overburden pressure was applied to a core plug by a manual pressure generator and maintained throughout the experiments within 1000.0±1.4 psi. The sample was exposed to the flowing brine solution (0.6 M NaCl) at fluid velocities varying from 1.48×10^{-5} to 1.48×10^{-3} m/s (corresponding to volumetric flowrates varying from 1 to 100 mL/min). Variation of permeability for the sample is monitored and recorded in real-time by a data acquisition system. A stage of sample permeability stability within 3.1 % was achieved for each fluid velocity, after which the flowrate was changed to a higher one. Four effluent samples were collected for the entire time period for each flowrate.

The procedure, which is described in detail elsewhere (Badalyan, Carageorgos et al. 2012), was used to study the effect of fluid velocity on particle mobilisation in rock fragments. Rock fragments with sizes varying from 4 to 6 mm and borosilicate glass beads of 30-50 μm in diameter formed a composite porous medium (CPM). All fragments were washed in 0.6 M NaCl solution to remove drilling mud. Fluid flowrates vary from 3.61×10^{-5} to 3.61×10^{-3} m/s (corresponding volumetric flowrates vary from 1 to 100 mL/min). The remaining procedure is similar to that used for the core plug.

Formation damage at various fluid ionic strength. Fluid velocities of 1.476×10^{-4} and 3.61×10^{-4} m/s (from the Darcy range of velocities) were chosen to study formation damage on core and fragments, respectively. Fluid ionic strength was declined step-wise from 0.6 to 6.24×10^{-5} M NaCl (the last ionic strength corresponds to deionized MilliQ water with electrolytic resistivity of 18

MOhm×cm at 25 °C). Variation of sample permeability at each ionic strength of fluid was monitored and recorded in real-time. When sample permeability reached stabilization (indicating that no more particles are mobilised, fluid with the lower ionic strength was pumped through the sample (core or CPM). Effluents were collected for each ionic strength for core and CPM samples.

Concentrations of particles and their size distributions for all effluents were measured by a portable particle counter PAMAS S4031 GO (PAMAS GmbH, Salzuflen, Germany; later in the text referred to as PAMAS) with the detailed preparation and measuring procedure presented elsewhere (Badalyan, Carageorgos et al. 2014). The remaining effluents are filtered through a 0.45 μm nylon filter, and dried in the atmospheric oven at 60 °C for 12 hours. Philips XL30 Scanning Electron Microscopes coupled with the thin film Energy Dispersed Analysis of X-rays detector (EDAX) is used for imaging of dried fines and X-ray analyses for the identification of minerals.

Zeta-potentials for fines used for calculation of Derjaguin-Landau-Verwey-Overbeek (DLVO) total interaction potential energy are measured by Zetasizer Nano Z (Model ZEN3600, Malvern Instruments Ltd., Worcestershire, UNITED KINGDOM) at various ionic strengths of suspensions and pH ≈ 7.2. Zeta potentials for sand are adopted from (Cerda 1987). The procedure for calculation of DLVO total interaction potential energy between fines and sand is presented elsewhere (Badalyan, Carageorgos et al. 2014).

3. RESULTS AND DISCUSSION

3.1 Fluid velocity-induced formation damage

Linear relationship (R^2 = 0.998) between pressure drop across a core plug and fluid velocity is observed for the entire fluid velocity range as follows from Figure 2a. This means that Darcy's equation can be used for calculation of core permeability. This is an indication that all velocities used in the present study fall into the Darcy's region. Fluid velocity of 1.476×10^{-4} m/s (corresponding to 10 mL/min) is used to study the effect of fluid ionic strength on particle mobilisation (see Section 3.2).

The average rock porosity from the log interpretation for Strzelecki-17 well for the depth of 1673.0-to-1676.7 m is equal to about 16 % according to the well completion report (Delhi Petroleum Pty. Ltd. 1983), which reasonably agrees with the result of the present study according to Table 1. Average core permeability for the depth range of 1673.0-to-1679.2 m is equal to about 96.7 mD according to the routine core analysis as reported in (Delhi Petroleum Pty. Ltd. 1983). However, the first sample tested for permeability came from the depth of 1677.0 m according to (Delhi Petroleum Pty. Ltd. 1983), which is almost 3.6 m deeper than Strz-17/c sample used in the present study. The value of 96.7 mD is almost 5-times higher than that measured in the present study (21.03 mD). Taking into account that permeability of cores varies significantly from about 96.7 to 0.62 mD over the depth range of 1673.0-to-1677.9 m the agreement can be regarded as satisfactory.

Permeabilities of the rock fragments were determined according to a procedure described in (Badalyan, Carageorgos et al. 2014). The obtained results are presented in Figure 2. All rock samples showed initial increase for permeability in the fluid velocity range from 3.61×10^{-5} to 7.21×10^{-4} m/s. This behavior differs from the results for sandstones core plugs and fragments from Ladbroke Grove-1 and Salamander-1 wells which showed slight permeability reduction with fluid velocity. The weighted mean size of the mobilised and collected particles from Strz-17/c and Strz-17/f are equal to 0.69±0.10 μm and 0.67±0.11 μm, respectively. Approximate mean pore-throat diameters for Strz-17/c, Strz-17/f, Cls-1-1/f, Cls-1-2/f and Cls-1-3/f samples are calculated via a capillary model according to (Rosseau, Hadi et al. 2008) using data for rock porosities and permeabilities after stabilisation and are equal to 3.08, 3.14, 3.73, 4.29 and 5.33 μm, respectively. Permeability increase for all samples could be explained by the mobilisation of particles and their passage through core/fragments without capturing. Stabilisation of permeabilities at higher fluid velocities is the result of no more particles being available to be mobilised only by hydrodynamic force.

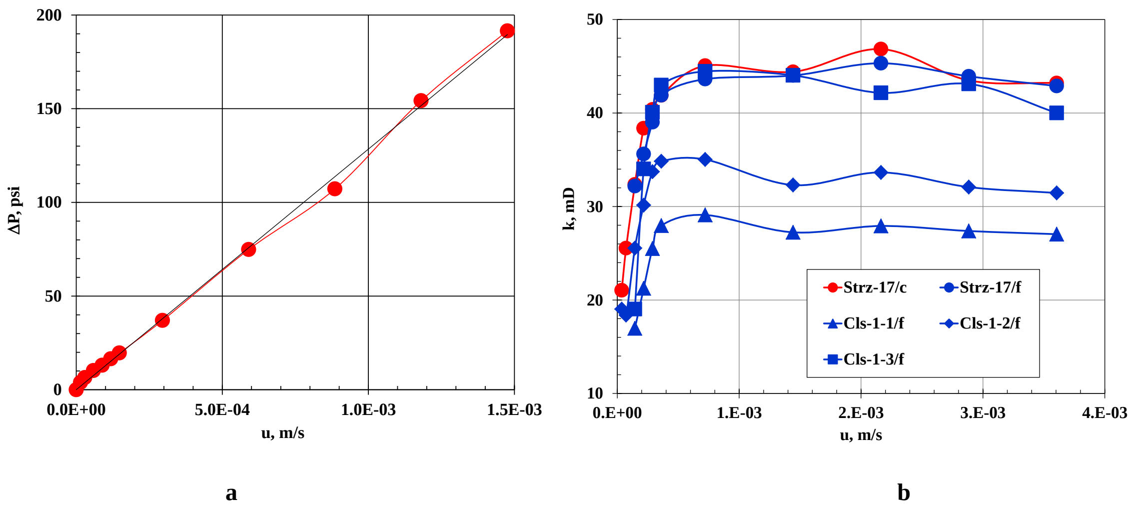

Figure 2: Experimental data for core plug and fragments: (a) pressure drop across the core plug *vs* fluid velocity for Strz-17/c; (b) average core plug and fragments permeabilities *vs* fluid velocity.

Unexpected high outlet particle concentration at low fluid velocity for Cls-1-3/f is explained by the presence of the so-called "loose" particles (not electrostatically attached to the surface of sand grains) which can be removed by low fluid velocity as follows from Figure 3. High fluid velocity mobilizes more particles from Strz-17/c and Cls-1-1/f than from the remaining rock samples.

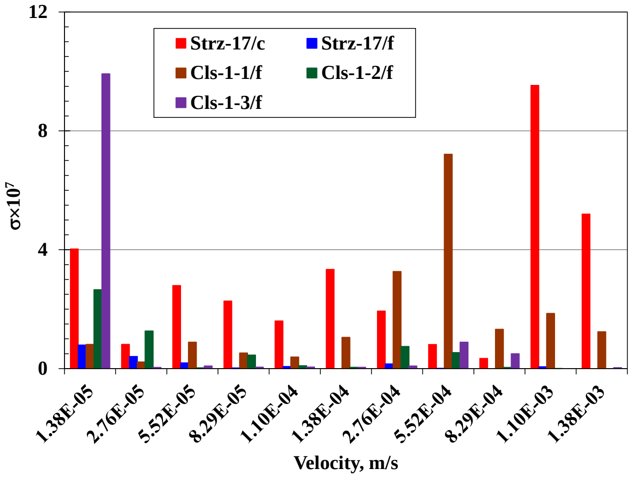

Figure 3: Particle concentration in effluents at various fluid velocities.

3.2 Low ionic strength-induced formation damage

Decline of fluid ionic strength from 0.6 M to 6.24×10^{-5} M NaCl reduced permeability for Strz-17/c from 42 to 28 mD according to Figure 4a. The most formation damage is observed for ionic strengths of 0.001 and MilliQ water and is supported by high concentration of mobilised and collected fines in the respective effluents (see Figure 5). Increase of water pH from 7.2 to 10 insignificantly reduces this sample's permeability. It means that although significant repulsion exists between clay particles and sand, no more particles are mobilised. Application of the new methodology for the evaluation of permeability for fragments resulted in a good agreement between permeabilities for Strz-17/c and Strz-17/f samples. Ionic strength of formation water for Strzelecki-17 well is 0.08 M equivalent to NaCl according to Table 2. At this ionic strength, only a minor reduction in permeability was observed for Strz-17/c; likewise the amount of collected fines was not significant at this ionic strength for the flowing fluid. Therefore, at ionic strength of reservoir water, fines migration results in insignificant permeability decline from 42 to 40 mD for Strz-17/c and Strz-17/f samples. Permeabilities for Cls-1-1/f, Cls-1-2/f and Cls-1-3/f also decline with lowering ionic strength of fluid according to Figure 4b. Although permeabilities for all Cls-1 samples decline by about 25-35 % at the lowest ionic strength for reservoir water (0.05 M NaCl), the residual permeabilities for these samples (16.5, 23.9 and 30.7 mD, respectively) are probably sufficient to produce commercial quantities of geothermal fluids.

Well	Total chloride, mg/kg (ppm)	Ionic strength, M
Strz-17	4400	0.08
Cls-1	4250	0.07
Cls-1	2800	0.05

Table 2. Ionic strength (equivalent to NaCl) of formation water for Strz-17 and Cls-1 wells.

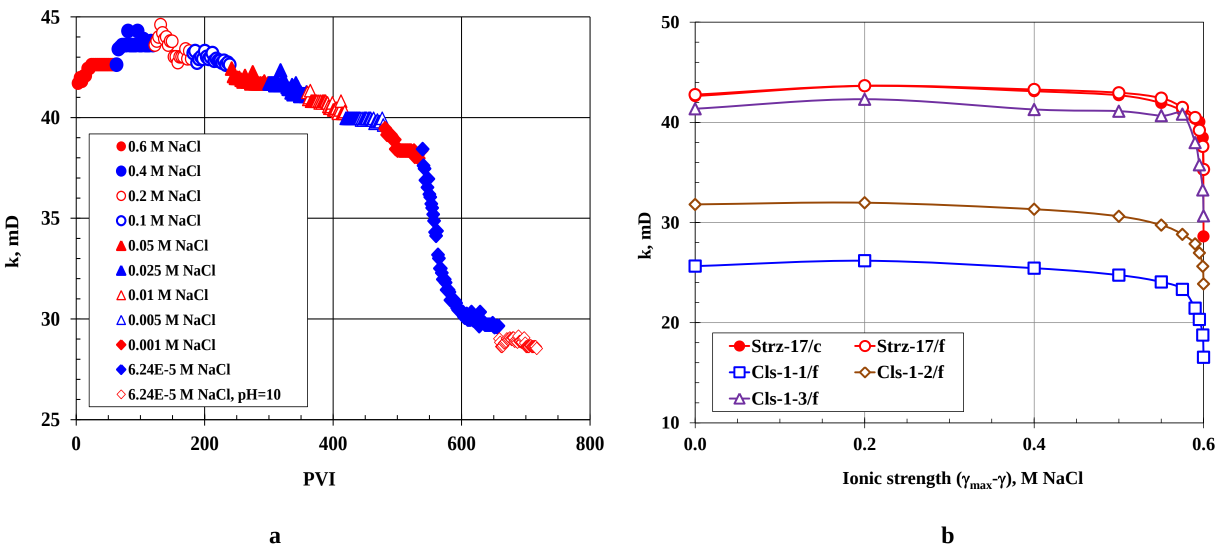

Figure 4: Variation of permeability with declining ionic strength: (a) Strz-17/c; (b) permeabilities for all studied samples.

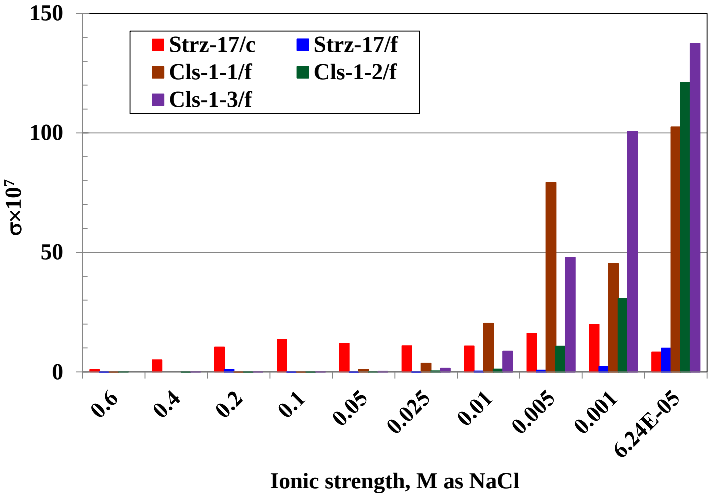

Figure 5: Concentration of fines in effluents at various fluid salinities.

3.3 DLVO interaction between particles and sand

Zeta potentials for released and collected fines for all studied rock samples as function of ionic strength of flowing fluid are presented in Figure 6. Zeta potentials for sand are adopted from (Cerda 1987).

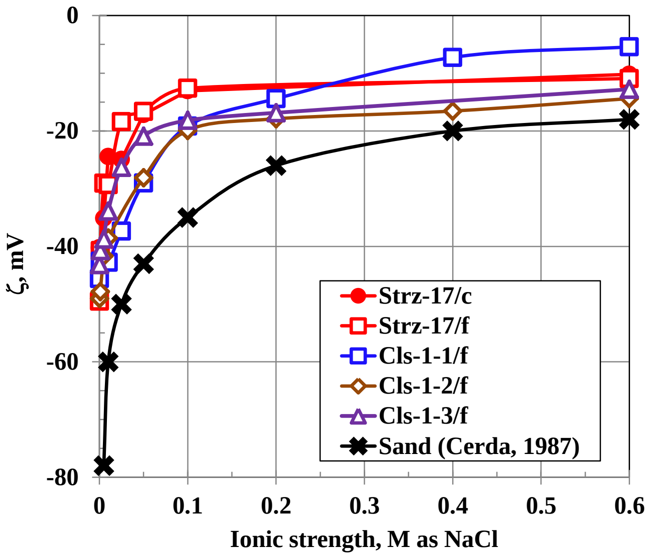

Figure 6: Zeta potentials for studied rock core and fragments.

Interaction between particles and porous matrix (sand) is quantitatively described by the DLVO theory (Derjaguin and Landau 1993; Verwey and Overbeek 1999). The DLVO total interaction potential energy, V_{tot}, is the sum of interaction potential energies arising from the attractive long-range London-van der Waals forces, the short-range attractive/repulsive electrical double layer and Born repulsion forces, respectively. The positive sign for V_{tot} is an indication of the domination of the repulsive EDL and Born forces over the attractive LW forces resulting in particle-sand repulsion and mobilisation of fines. Attraction of particles to sand occurs when the attractive LW forces dominate over EDL and Born forces, and the sign for V_{tot} changes to negative. When there is particle-sand attraction, particles with sufficient energy can overcome the interaction potential energy barrier, approach the surface of a porous medium at a few nanometers separation distance and be irreversibly attached to it in the primary energy minimum. The presence of a secondary energy minimum at larger separation distances can lead to a reversible particle capture provided the particles have insufficient energy for escape.

The DLVO total interaction potential energy between fines and sand varies with separation distance according to Figure 7. The magnitude of repulsion (higher positive values for DLVO total interaction potential energy) for Cls-1-1/f is greater than that for Strz-17/c sample, indicating than particles are more readily to be mobilised from Cls-1-1/f at low fluid salinities: this observation is supported by data presented in Figure 5 - more fines were collected from Cls-1-1/f effluent samples than those from Strz-17/c and Strz-17/f. Some particles can reside in shallow secondary minimums (at salinities of 0.2, 0.1 and 0.05 M NaCl), meaning that they can be mobilised by the flowing fluid contributing to formation damage. Similar behaviour was observed for other samples Cls-1-2/f and Cls-1-3/f. Particles from Cls-1-1/f sample repulse from sand and can't be re-attached to sand during flow at ionic strength of reservoir water varying from 0.05 to 0.07 M NaCl due to the reduction of the depth of the secondary energy minimum.

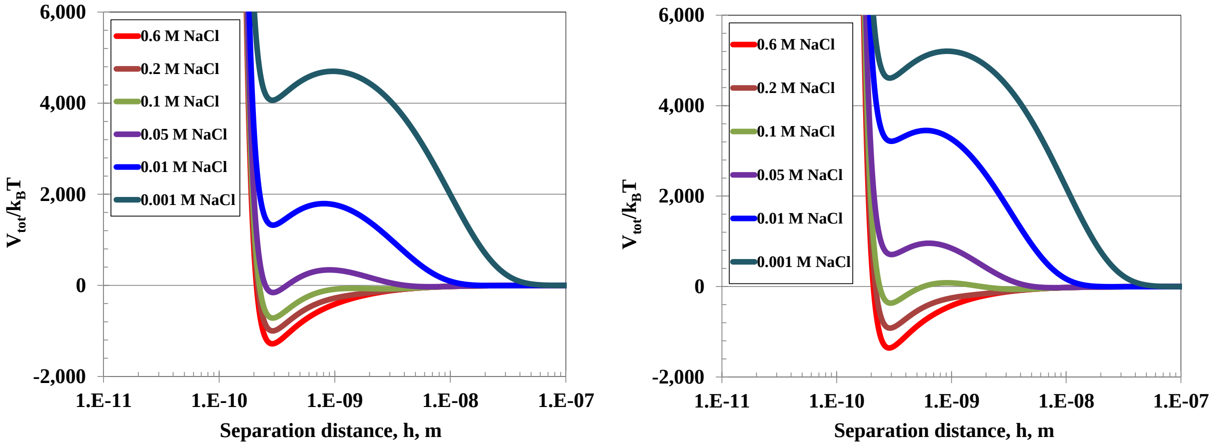

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Figure 7: Total potential of interaction for clay-water-sand system for Strz-17/c (a) and Cls-1-1/f (b).

3.4 SEM-EDAX results

The results of SEM-EDAX analysis for fines released from Cls-1-1/f sample are shown in Figure 8. Flakes of clay minerals are visible in SEM image in Figure 8a. Although the morphology of these clays indicate the presence of chlorite $(Mg, Al, Fe)_{12}[(Si, Al)_8O_{20}] (OH)_{16,}$ their EDAX spectrum (see Figure 8b) is more indicative of illite $K_{1\text{-}1.5}\ Al_4[Si_{7\text{-}6.5}\ Al_{1\text{-}1.5}\ O_{20}]\ (OH)_4$. However, the moderate iron content is an indication of the formation of chlorite (Vortisch, Harding et al. 2003). Therefore, this can be treated as mixed-layer illite/chlorite mineralogy.

As no additional information on the mineralogy of fines was available before and after this study, it should be mentioned, however, that SEM analysis alone might not be definite enough and XRD analysis would be required for a more precise determination of fines mineralogy. Quantities of collected fines didn't allow us to carry out XRD analyses.

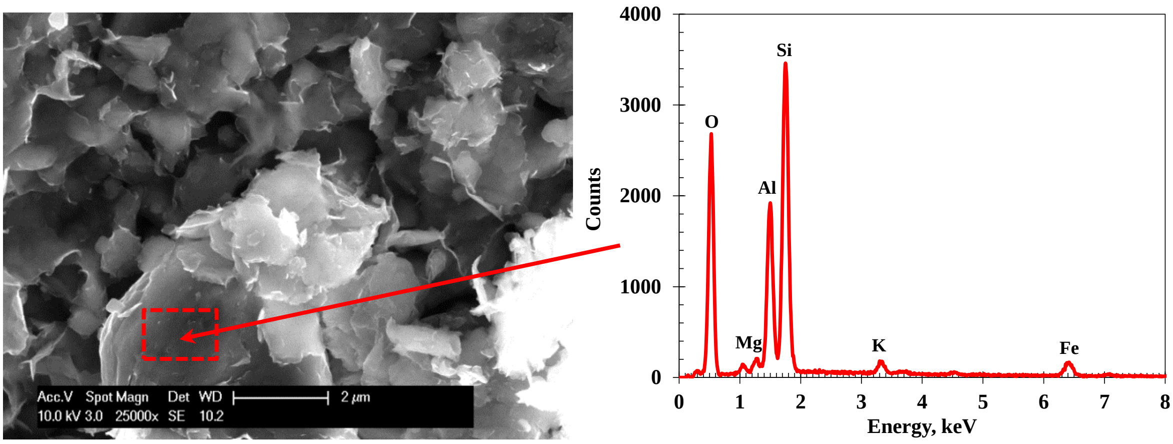

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Figure 8: SEM-EDAX for Cls-1-1/f: (a) SEM image, (b) EDAX spectrum.

5. CONCLUSIONS

Permeability for rock samples increased with fluid velocity since mobilised particles passed through a porous matrix without being captured. Stabilisation of rock permeabilities was reached at medium and high fluid velocities and indicates the inability of hydrodynamic forces to mobilise more particles.

Low ionic strength reservoir water from Celcius-1 geothermal well led to greater repulsion between particles and sand matrix and the mobilisation of fines.

Clay minerals of transitional illite/chlorite mineralogy were identified using SEM-EDAX analyses and were found to be the main component of mobilised fines. However, they were found to be of only minor significance for formation damage at low ionic strength of formation water.

Appreciable residual permeabilities for rock samples from Celsius-1 well may indicate that the well can produce commercial quantities of geothermal fluids.

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