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Scaling and Corrosion Mitigation in Olkaria Using Brine and Condensate Mixing Method

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ABSTRACT

pH monitoring and management is an integral part in geothermal operations and utilization. In Olkaria geothermal field, reinjection of the spent geothermal waters from the power plants is a routine practice and is an integral part of sustainable geothermal utilization. In order to safely and efficiently reinject the waters without any problems of scaling or corrosion, pH and temperature of the condensate need to be maintained within the design requirements so that it does not corrode the carbon steel components of the power plant or the casing of the cold reinjection wells. To achieve this, the pH is maintained within the required limits of 6.0 to 8.5 for the power plants reinjection fluid. Current practice in Olkaria is treatment of the acidic condensate with sodium carbonate (Na_2CO_3). This method was introduced in the Olkaria field by the Sinclair Knight Merz in 2001 in Olkaria II and later replicated in other new plants that have come online since then. The suspected major concern with this method is side reactions from the impurities in the chemical such as silicates and sulphides. In this study, an alternative method of pH modification in geothermal power plants is explored which is mixing the spent geothermal waters from the power plants with the separated waters (brine which has a higher pH of >8) before reinjecting into the cold reinjection wells. This approach assesses the scaling potential before and after mixing the fluids and how the pH changes upon mixing the condensate and brine in different mixing ratios from 90% condensate and 10% brine to 50% condensate and 50% brine. Since the aim is to raise the pH of the condensate, more condensate to brine is taken. This is done using PHREEQC which is a geochemical modelling program code and WATCH. The PHREEQC program allows for simulation of mixing of various fluids while assessing their scaling potential for silica, calcite and anhydrite. The results from the study show that mixing the spent geothermal fluid from power plant and the separated water from the reinjection considerably lowers the calcite and silica scaling potential in the reinjection aquifers and also raises the pH of the fluid. Upon producing from this fluid after heat up, the mixing does not affect the scaling tendencies much. The scaling potential of anhydrite is increased considerably but this does not pose any danger to geothermal operations.

1. INTRODUCTION

KenGen operates four conventional power plants Olkaria I, II, I additional unit and olkaria IV. The Olkaria I additional unit was commissioned in two phases. The first unit was commissioned in October 2014 and the second unit in January 2015: each 75 MWe. The plant is a single flash condensing type with evaporative cooling towers and running on a Toshiba turbine. Each unit produces about 18,600 m^3/h of condensate which is intermittently reinjected into the cold reinjection wells at a temperature of 37.3°C -45°C (KenGen, 2012). The continuous condensate and brine reinjection is to sustain the geothermal reservoir by providing recharge into the reservoir and therefore limiting the pressure draw down. The condensate is at very low pH due to dissolved acidic gases such as carbon dioxide and hydrogen sulphide. The amount of non-condensable gases at the plant is 1.503% wt. Non condensable gases are either emitted to the atmosphere through the gas extraction system or dissolved in the condensate. The pH of the condensate greatly depends on the amount of dissolved carbon dioxide and hydrogen sulphide. These gases being classified as acidic gases, lower the pH of the condensate to about 2.5.

Geothermal power generation involves production of electricity from steam which in turn generates more condensate which normally is acidic in nature. The pH of the condensate normally ranges from 2.5 – 3.0. The condensate is always in contact with the carbon steel components of the power plant installations and the components of the disposal wells. The disposal wells casings and the condensate piping, the valves, the pumps, separators and liners are always prone to corrosion and therefore failure. Natural geothermal waters are complex and often with very high concentrations of the dissolved solids. The waters chemistry varies from one well to another and from one power plant to another depending on factors such as well head pressure, hydrochemistry, flow rates, temperature, pH and the presence of solid particles suspended in the water(Mundenk,2013). The corrosiveness of the waters are largely elevated by the presence of corrosive species such as oxygen, hydrogen sulphide, carbon dioxide, ammonia, chloride and hydrogen ions (pH). Components such as oxygen and hydrogen sulphide can cause massive corrosion even in low concentrations (Gallup,2011). Most corrosions in geothermal installations occur in the absence of oxygen. Corrosion in the presence of carbon dioxide occurs due to the formation of carbonic acid which further affect the pH (Opondo, 2002). Scaling and corrosion occurs due to pressure drop, temperature changes and oxygen ingression.

To neutralize acidic pH of the condensate (pH 2.5) sodium carbonate is added to raise the pH to 6.0. The sodium carbonate treatment method was first introduced in Olkaria II in 2001by the Sinclair Knight Merz. This was after a pilot study on the effectiveness of neutralization of the condensate acidity with sodium carbonate. The sodium carbonate is injected at various points in the condensate flow line. A key area where the condensate treatment is done is the cold reinjection water line, circulation line to the cooling tower and the cooling tower basin. This is done to prevent: 1) acid corrosion of the carbon steel components of the plant, reinjection well casings and liners, 2) balance the primary and the secondary gas emissions from the condenser: 3) Prevent cooling tower fouling/clogging of the cooling tower fills by the elemental sulphur which is deposited in the condenser where the gases come in contact with the oxygen and also in the cooling tower distribution nozzles where there is sudden temperature drop. The Figure 1 shows the various points in the geothermal system where scale deposition and corrosion takes place.

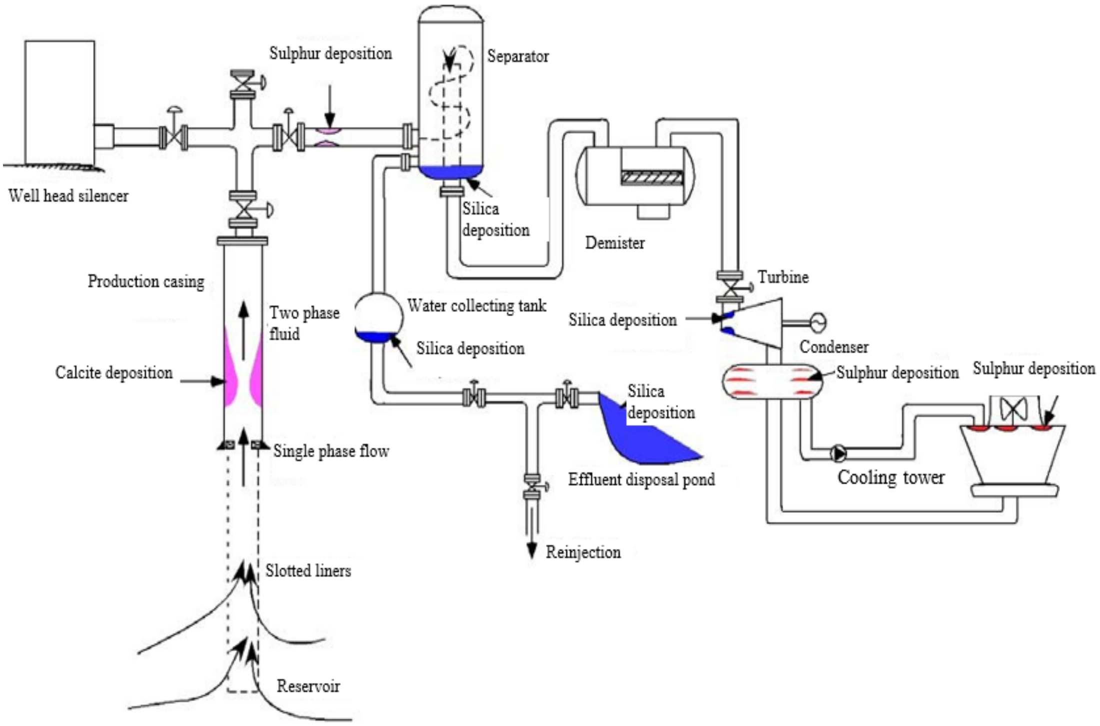


Figure 1: Areas of scale deposition in geothermal system (Tassew, 2001)

Scaling in the turbine blades and corrosion of the cold reinjection wells, clogging of the cooling tower film pack due to elemental sulphur deposition and microbiological growth and corrosion of the main steam line can lead to a plant shut down and have been experienced in the Olkaria I Additional Unit in the recent past. This is majorly caused by the low pH of condensate circulating in the plant (KenGen internal reports). Areas where corrosion affects are the steam and condensate pipeline and cold reinjection wells OW-801R1. Corrosion has also been observed at the drain pots just before the scrubber and might be caused by corrosive carry overs due to inefficient separation of steam and brine

Some of the methods employed across the world to mitigate scaling and corrosion include dilution of the brine with condensate. Mixing condensate with brine in predetermined fractions helps increase the pH of the resultant mixture, and maintain temperature above the silica saturation temperature to avoid deposition in the well bore. This has been successfully implemented in Hellisheiði power plant in Iceland and has yielded positive results (Sigfússon and Gunnarsson, 2011). This therefore is evaluated for the Olkaria field. Instead of neutralizing the condensate with the sodium carbonate, it is mixed with the brine separated from the wells in the production field. The brine from Olkaria field is highly alkaline at pH of above 9 and temperature of above 150°C. The condensate on the other hand is at pH of 2.5 and temperature of 45°C. The aim therefore, is to carry out study on the viability of mixing the brine with the condensate to avoid scale deposition and the acid corrosion at the plants installations by raising the pH and mitigate corrosion of the cold reinjection wells with case study being Olkaria East field. The study therefore, focuses on the effects of injecting the mixed fluids in the production and reinjection aquifers.

2. OBJECTIVE

The objective is to investigate in details the chemical composition of the brine and condensate. Evaluate the possibility of scaling and corrosion by the mixed fluid: This involves determining the best mixing ratios for the brine and condensate from the Olkaria IAU power plant and the separated brine from the representative well OW-703. OW-703 is an infield hot reinjection well located in the Olkaria North East field. The proposed ideal mixing ratio will be achieved by mixing simulations at different ratios using PHREEQC computer code program (Parkhurst and Apello, 1999).

The simulation also evaluates the ultimate temperature that prevents scaling in the reinjection wells and further scaling when we start producing from the mixed fluids in the production aquifers. For evaluation of the effect of the mixing, the mineral scaling potential and pH of the fluids before and after mixing is assessed. The production well used in the simulation of the effect of the dilution in production aquifers is OW-38A. The OW-38A has had scaling problems based on the monitoring data. Therefore, this is ideal well for simulation of the effects of the reinjection fluid.

3. CORROSION IN OLKARIA GEOTHERMAL FIELD

Corrosion in high temperature geothermal installations mainly occur in well casings, cold condensate injection pipelines of carbon steel material, wellhead equipment and first stage turbine blades. In power plants utilizing direct contact condensers, cooling circuit water always have low pH of < 2.5 which is mainly as a result of acidic gases CO_2 and H_2S dissolved in the steam. Low pH condensate causes deterioration of the carbon steel. Corrosion in the presence of oxygen is more severe (Kizito, 2002). The low pH in the condensate occurs when there is conductive cooling along the steam pipelines so the steam condenses allowing for dissolution of CO_2 and H_2S. Olkaria geothermal power plants utilises the direct contact condensing turbines where the low pH is a common challenge. Most of the corrosion occurring in the power plants and the steam condensate pipeline is mainly as a result of the low pH. Figure 3 below shows corrosion in some of the cold reinjection wells in Olkaria. High concentrations of anions such as Cl^- and SO_4 in the presence of low pH steers the process of pitting corrosion (Gallup, 2011) although this is yet to be verified for Olkaria case.

Figure 2: Corroded reinjection well OW-902A in Olkaria Domes field

The corrosion that happens in the Olkaria installations varies from pitting, to localised/ general corrosion and crevices. The mechanism for scaling and corrosion greatly involves the following contaminants and conditions in the brine and steam in geothermal installations:

- Carbon dioxide;
- Hydrogen sulphide;
- Hydrogen chloride;
- Iron sulphide;
- Sulphates;
- Oxygen;
- Temperatures;
- Suspended solids;
- Flow characteristics;

In the presence of these, the rate of scaling and corrosion can be elevated and the attack may hinder greatly the operation of the power plants and running of the production and reinjection wells.

4. LOCATION AND GEOLOGICAL SETTING OF OLKARIA GEOTHERMAL COMPLEX

4.1 Location of Olkaria Geothermal complex

The Olkaria high temperature geothermal field is located on the floor of the Kenyan rift about 120 km to the North East of Nairobi and lies within the Hells gate National Park. The resource is estimated to cover an area of about 204 km^2. The Olkaria geothermal complex is among the 14 prospects in the Kenyan rift system. Among the prospects, Olkaria, Eburru and Menengai are under exploitation and are the main geothermal fields that have been currently under exploitation. The total estimated potential of the prospects is 10000 MWe. Figure 4 shows the geothermal prospects and the fields in Kenya.

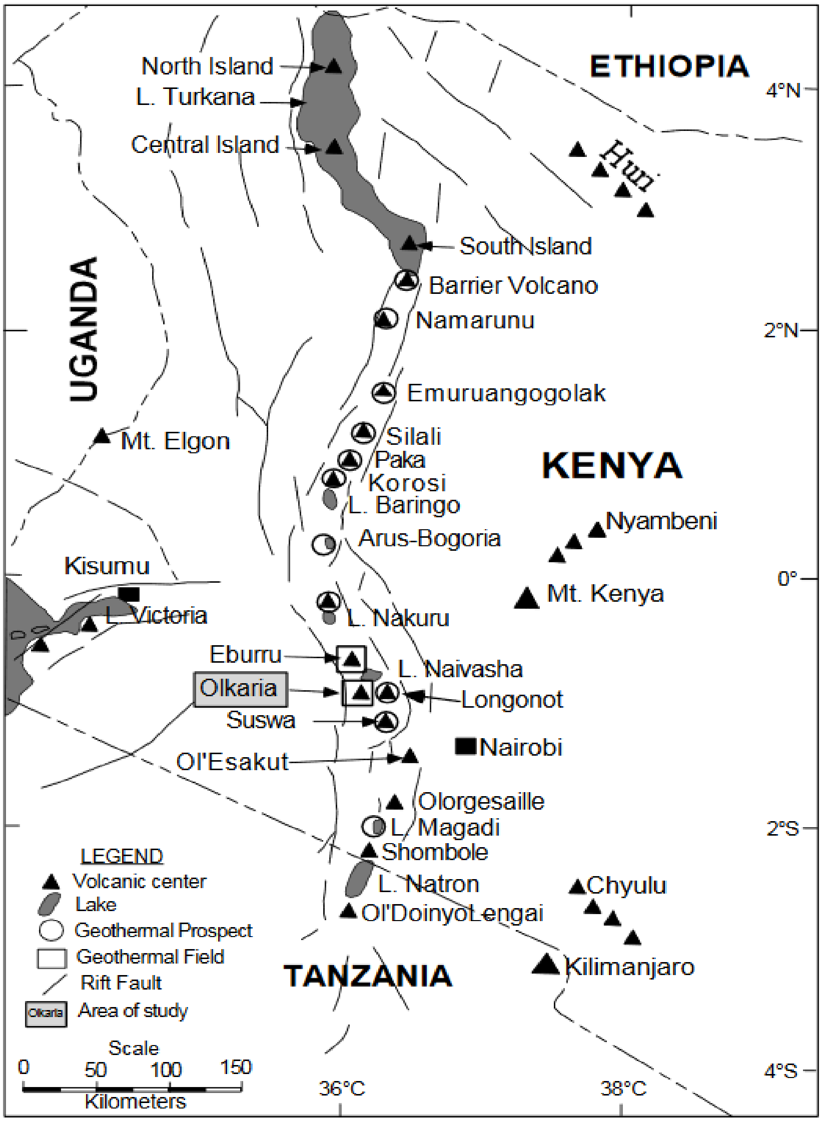


Figure 3: Kenya Geothermal prospects (Lagat, 2004)

4.2 Geological setting of Olkaria

The Olkaria geothermal system is associated with an old central volcano which collapsed leaving a large caldera of about 5 km in diameter defined by ring structure and rhyolitic domes (Omenda, 1998). Rocks occurring on the surface are majorly quaternary comenditic, pumice fall and volcanic ash deposits of late Pleistocene to Holocene. Trachytic flows appear to the southern part of the geothermal field below thick pyroclastic commonly associated with the Longonot and Suswa eruptive (Omenda 1998). The complex is classified as remnant of an old caldera and is bounded by Eburru complex to the North, to the east by the Longonot and to the south by the Suswa volcanoes and to the west by the Western rift margin. The area comprises of many small active volcanic centres occurring either as steep sided domes formed as lavas and or pyroclastic rocks or as thick lava flow of restricted lateral extent. The Olkaria complex together with Eburru is termed as rhyolitic volcanic complexes; Menengai, Longonot and Suswa are classified as the trachytic caldera volcanoes. The geology is dominated by the Pleistocene and Holocene. Holocene comenditic rhyolitic flows on the surface and basalts, trachyte and tuffs in the subsurface. Basaltic dykes, syenitic, micro-granitic and granitic intrusions are also common (Lagat, 2004). The litho-stratigraphic structure in the area is nearly horizontal (Muchemi, 1999). Based on rock cuttings and cores, the general litho-stratigraphy of the greater Olkaria complex can be divided into two: the western sector characterised by the Mau tuffs and secondly the east of Olkaria Hill which has the plateau and olkaria basalts. Omenda (1998) discussed the formations of Olkaria in sequence of Mau tuffs, plateau trachyte, olkaria basalts and upper olkaria volcanic. The Mau tuffs are unique to the western sector while the trachyte and basalts are unique to the eastern sector. Lagat (2010) further summarised the most common secondary minerals in the field as: calcium silicates, clays, oxides, silica minerals, zeolites, pyrites, fluorites, calcites and albites. Figure 5 above shows the surface geology of the Olkaria complex

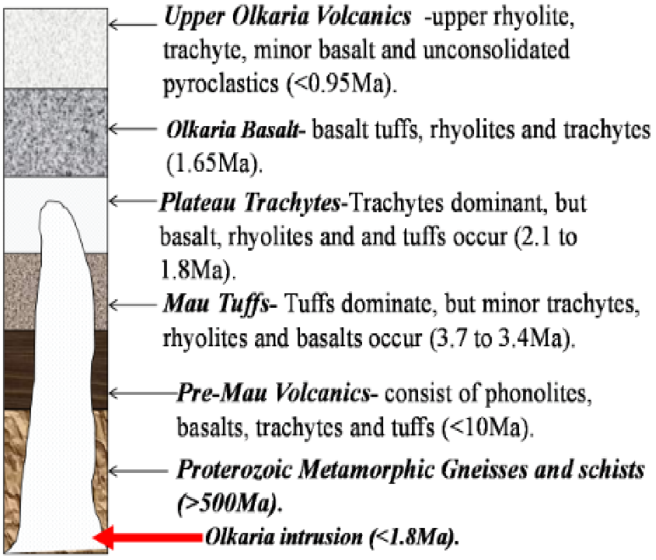


Figure 4: Olkaria complex lithological units (Modified from Omenda, 1998)

5. STUDY AREA

5.1 Olkaria East production field

The Olkaria IAU is located in the Olkaria East production field. The power plant receives steam from 26 production wells located in the East field with average enthalpy of about 2600 kJ/kg and depth of 3000 m. There are 7 hot reinjection wells with depth varying from 600 shallow reinjection wells to 1700 m classified as deep reinjection wells. There are 2 cold reinjection wells OW- 801R1 and OW-801R2 at a depth of 600 -1500 m. The production wells production casing is at 1200 m while the reinjection wells are cased at 270 m depth (Ng'ang'a 2014). The wells have an average wellhead pressure of 10 bars. The fluid discharged from these wells is dilute sodium chloride type (Otieno and Kubai, 2013).

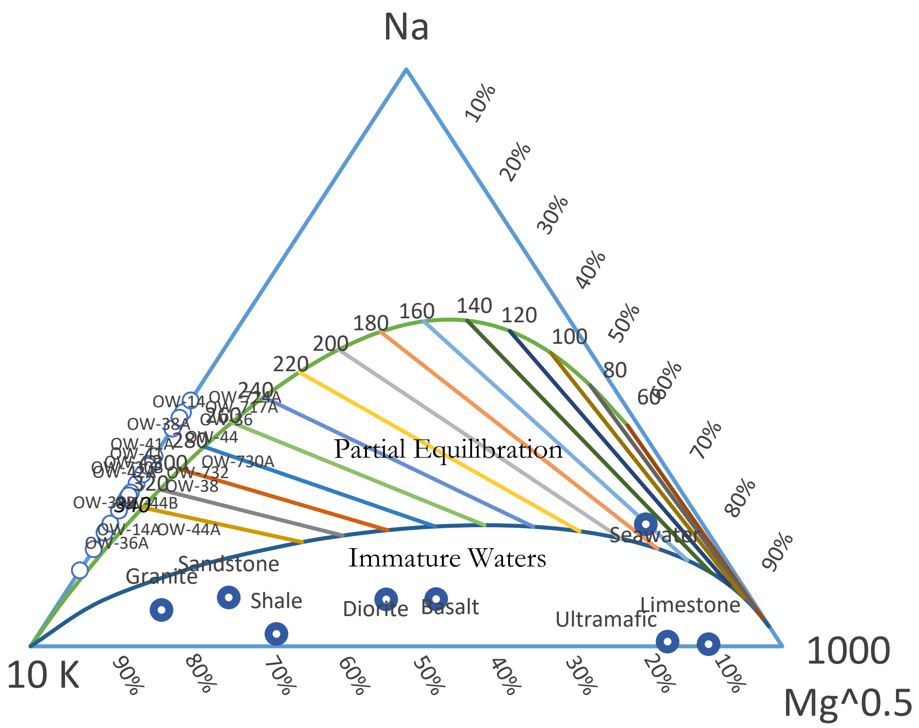


Figure 5: Olkaria East Geothermometers

The field has high chloride content of 200-350 ppm while bicarbonate concentration in Olkaria ranges from 10000 ppm in Olkaria West field to less than 10 ppm in the Olkaria East field (Wambugu, 1996). Figure 8 and 9 below show the fluid classification and geothermometers of Olkaria East

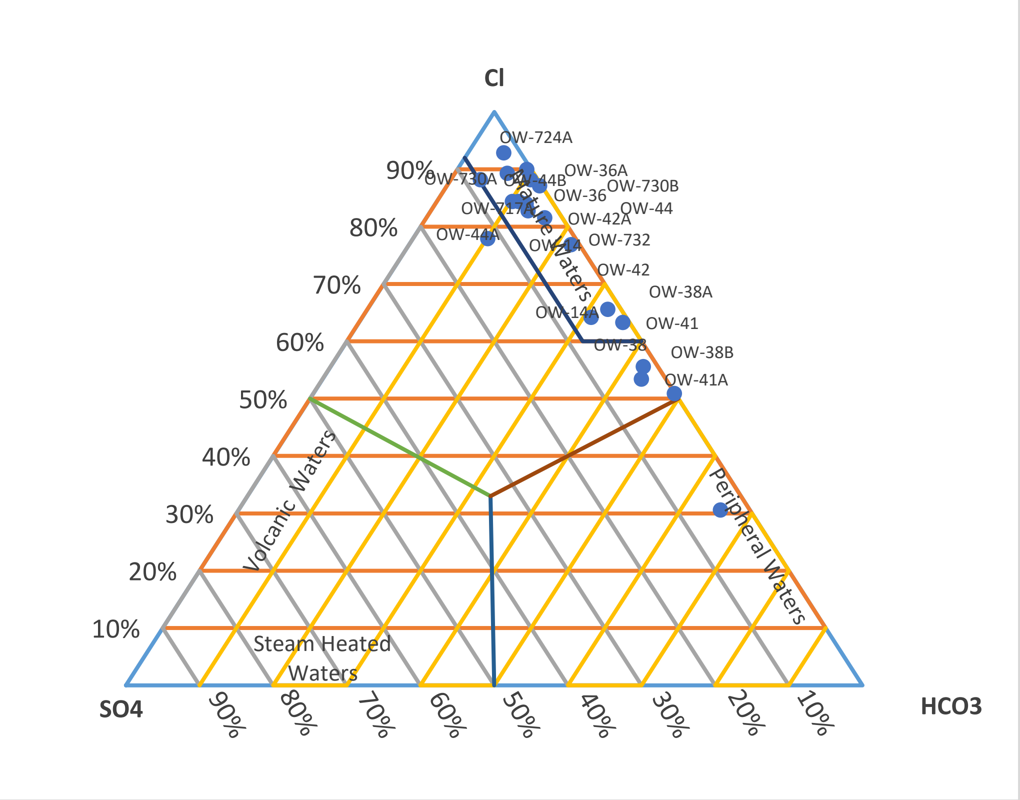


Figure 6: Olkaria East fluid classification

6. METHODOLOGY

6.1Sampling and analysis

Sampling and analysis were done according to the procedures by the (Ármannsson and Ólafsson, 2006). The power plant samples were sampled from the condenser outlet at a temperature of 45°C. Analysis of H_2S was done in the field by titrating with 0.001 M $HgAc_2$ with dithizone as the indicator. 5 ml of NaOH was put in 250 ml beaker and 5 ml of Acetone added. In the mixture 1 ml of sample was added and titrated with the mercuric acetate. The cations samples were filtered and treated with 0.8 ml concentrated HNO_3 to fix the ions to prevent adsorption on the walls of the sampling container. Anions samples sulphate: was precipitated to prevent the sulphide from oxidising to increase the concentrations of the sulphate therefore 2 ml of zinc acetate is added in the 100 ml sample to precipitate the sulphide in the sample. One sample was collected for the chloride, CO_2 and pH measurements. Silica from the steam condensate required no dilution because it is in less concentrations. The anions were analysed using Ion chromatography (IC). The cations were analysed using Inductively Coupled Plasma Optic Emission spectrum (ICP-OES).

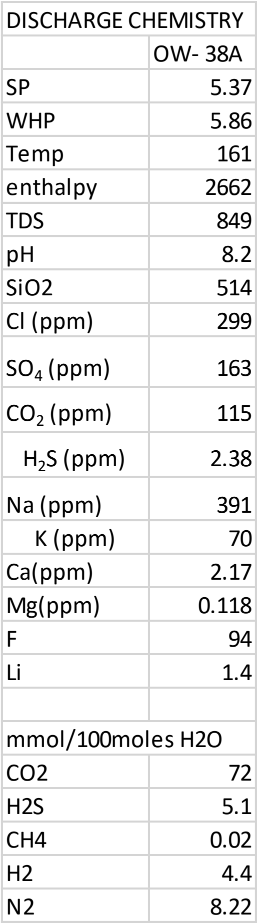
The condensate data was obtained from Olkaria I Additional Unit power plant. Olkaria IAU unit IV and V have slightly different chemistry. This then required that the condensate from the two units are mixed in PHREEQC to attain a composition that would be used to dilute the brine from the reinjection wells. The condensates were mixed in the ratio 1:1 and reaction temperature of 45°C. The mixed condensate was then heated up in WATCH to a temperature of 150°C to simulate the hot reinjection conditions in Olkaria. The pH of the mixture was obtained from PHREEQC. The output from WATCH was then used as input file in PHREEQC to carry out mixing with the brine from the OW R3 and OW 703

The wells discharge samples were collected based on high temperature sampling methods described by Armansson (2006). The chloride was analysed using the argentometric titration method where the sample is titrated with 0.1 M $AgNO_3$ and potassium dichromate as the indicator to a permanent orange colour preceding the brick red colour. Silica analysis was done using the spectrophotometric method where the absorbance of the β-molybdic acid complex is measured at a wavelength of 410 nm. The major cations were analysed using the flame photometer. Total carbon dioxide was analysed by titrimetric method by adding $AgNO_3$ prior to analysis to remove the hydrogen sulphide that may be present in the sample. Sulphate was analysed using indirect spectrophotometric with barium chromate and bromophenol blue. The sample is prior acidified with the zinc acetate to eliminate possible interferences from the bicarbonate and the sulphide. After sample preparation it was analysed in the UV-Vis spectrophotometer at an absorbance of 385 Nm

TABLE 1: Olkaria IAU condensate chemistry

	CONDENSATE CHEMISTRY		
parameter	UNIT 4	UNIT 5	UNIT 4&5 MIXED
Tref	45.0	45.0	45.00
TDS	412.0	616.5	970.00
pH @20°C	2.8	2.9	2.84
SO4	105.4	128.4	234.34
Cl	0.1	0.4	0.48
CO2	14.3	33.0	46.52
F	0.3	0.5	0.80
SiO2	0.4	0.6	1.01
Ca	0.2	0.9	1.07
Na	3.5	33.5	37.08
K	0.1	0.7	0.77
Mg	0.0	0.2	0.21

TABLE 2: Discharge chemistry



DISCHARGE CHEMISTRY	
	OW- 38A
SP	5.37
WHP	5.86
Temp	161
enthalpy	2662
TDS	849
pH	8.2
SiO2	514
Cl (ppm)	299
SO_4 (ppm)	163
CO_2 (ppm)	115
H_2S (ppm)	2.38
Na (ppm)	391
K (ppm)	70
Ca(ppm)	2.17
Mg(ppm)	0.118
F	94
Li	1.4
mmol/100moles H2O	
CO2	72
H2S	5.1
CH4	0.02
H2	4.4
N2	8.22

6.2 Calculation of deep liquid composition

The geochemical interpretations are based on the results of samples collected at the surface. Clear and better understanding of the reservoir fluid chemistry can be achieved by re-calculating the surface fluid chemistry back to the reservoir conditions. The approach is based on two assumptions: a one phase liquid inflow only and excess enthalpy in the reservoir or assuming two phase fluid in the reservoir - liquid and vapour. Mass conservation is a key factor in this calculations as indicated by the equation 14 below:

$$m_i^t = m_i^v X + m_i^{lq}(1 - X) \tag{14}$$

where m_i^t is the total concentration of the ith component and m_i^{lq} and $m_i^v x$ are the concentrations of the liquid and the vapour phases respectively while x is the steam fraction.

For the enthalpy of the geothermal system, total enthalpy of the system is considered in which it is given by the equation 15 below:

$$h^t = h^v X^v + h^l(1 - X) \tag{15}$$

In which $h^t,\ h^v\ , and\ h^l$ are enthalpies of the system, vapour and liquid respectively. The steam fraction X is given by the following equation:

$$X = \frac{h^t - h^{lq}}{h^v + h^{lq}} \tag{16}$$

The WATCH program by (Bjarnasson, 2010) is then used to calculate the aquifer fluid composition from the data collected at the surface. In this case, the brine collected from the OW- 38A well at 161°C is recalculated back to reservoir conditions by heating to 240°C and boiling adiabatically in Watch. In this project the main aim of calculating the deep liquid using WATCH is to get the saturation states of various minerals that are scale forming in production aquifers before and after mixing with the diluted brine from OW-703.

TABLE 3: OW 703 Separated water chemistry

Parameter	Conc. in ppm
WHP	5.9bars
SP	6.00bars
Temp	162°C
Enthalpy	1355Kj/Kg
TDS	2642
pH@20°C	8.6
SiO_2	886.01
Cl	884.01
SO_4	24
CO_2	216.48
H_2S	1.42
Na	710.01
K	176
Ca	0.2
Mg	0.1

6.3 Simulation of mixing using PHREEQC modelling programme code and WATCH

Phreeqc is reaction path computer code program used for simulating variety of reactions in natural waters. It is used for speciation of chemical components, batch reaction, one dimensional transport and inverse geochemical modelling. In this project, Phreeqc is used to carry out fluid mixing, calculate saturation indices of scale forming components anhydrite, calcite and silica which are the most common scaling minerals in geothermal installations. The program is used to calculate the temperature effects on the various reactions using Van´t Hoff equation because it is critical in determining the possibility of mineral precipitation.

The brine discharge data was obtained from the hot reinjection well OW-703 located in the Olkaria North East production field.

Mixing of the separated brine from OW 703 with condensate was done in Phreeqc computer code program. The condensate composition, heated up in Phreeqc to 240°C to simulate the reservoir conditions was mixed with the brine from the well OW-703 in the ratios of 0.1:0.9, 0.2:0.8 ,0.3:0.7, 0.4:0.6 and 0.5:0.5. After mixing the resultant fluids were heated up to 240°C again to simulate the reservoir conditions in the field. Table 4 below shows the brine composition after mixing.

TABLE 4: Brine condensate mixture composition (ppm)

Ratio	pH	Temp(°C)	B	CO_3^{2-}	Ca	Cl	F	K	Mg	SO_4	SiO_2	Na	H_2S
0.9:0.1	3.12	56.33	1.42	50.02	0.50	87.75	0.36	17.95	0.10	107.20	89.20	87.93	0.25
0.8:0.2	3.86	67.66	1.26	77.23	0.47	175.25	0.32	35.52	0.10	97.96	177.88	157.32	0.39
0.7:0.3	5.98	78.99	1.10	104.44	0.43	262.76	0.28	53.09	0.10	88.73	266.57	226.70	0.53
0.6:0.4	6.50	90.32	0.95	131.64	0.40	350.28	0.24	70.66	0.10	79.49	355.26	296.10	0.67
0.5:0.5	6.88	101.65	0.79	158.84	0.37	437.78	0.20	88.23	0.10	70.26	443.95	365.49	0.81

The mixed fluid was boiled down in Watch from the heat up temperature of 240°C to 120°C. The mineral scaling potential was then evaluated for calcite, anhydrite and amorphous silica. The temperature and pH changes during boiling was also evaluated and tabulated as below in Table 5

TABLE 5: Mineral precipitation potential during mixing

Mixing ratios	pH	Temp	Calcite	SiO_2(a)	Anhydrite
0.9:0.1	3.12	56.33	-9.6	-0.3	-3.6
0.8:0.2	3.86	67.66	-7.9	-0.1	-3.5
0.7:0.3	5.98	78.99	-3.6	-0.01	-3.5
0.6:0.4	6.50	90.32	-2.7	0.04	-3.5
0.5:0.5	6.888	101.6	-2.1	0.08	-3.5

The brine mixture has a potential to precipitate only amorphous silica when mixed in the ratio 0.6: 0.4 and 0.5:0.5. All the other minerals are under-saturated for all the ratios.

The injected fluid can be of great impact in the production aquifers. They can cause mineral precipitation thus sealing off the permeable zones. Therefore, to determine the effect of reinjecting the condensate-brine mixture into the production aquifer, the condensate-brine mixture was then mixed with production fluid (brine) from OW-38A. The OW-38A is a production well located in the Olkaria East production field and its brine is reinjected in the Olkaria East field. The mineral scaling potential of the well was assessed before incursion of the condensate-brine mixture. This was done by heating up the well discharge chemical composition in Phreeqc to 240°C then boiling in watch from 240°C to 120°C. The brine from OW-703 mixed with condensate and the brine from OW-38A were mixed in the ratio 1:1. The Phreeqc output of the mixture was adiabatically boiled in WATCH in steps of 20°C from 240°C to 120°C. The mineral scaling potential for calcite, silica and anhydrite were evaluated and the pH changes recorded during the adiabatic boiling process

The evaluation of the mineral saturation potential involved all potential scale forming phases and also considered the adiabatic boiling of the aquifer fluid (total discharge), adiabatic boiling of the separated water and adiabatic boiling of the separated water and condensate mixtures. The results of these simulations are discussed below.

7. RESULTS AND DISCUSSION

7.1 Scaling potential in production aquifers of OW-38A

The mineral scaling potential in the production aquifers of well OW-38A located in the Olkaria East was evaluated by adiabatically boiling in watch to 120°C. This is to predict the baseline scaling tendencies in the well fluid before mixing with the separated water and condensate mixture during production. From the results, there is a high potential for calcite scaling in the wellbore. Calcium carbonate scale usually forms due to emission of CO_2 from the liquid during boiling. Evolution of CO_2 can also occur due to pressure drop in the well. This can occur in steam piping where there are bends. When pressure drops, the fluid experience substantial increase in the pH due to degassing. Considering the high temperatures in the well bore especially in Olkaria field where the temperatures are high (240°C), even a small concentration of calcite in the fluid will precipitate under these conditions. Production fluids with calcium have a potential to precipitate in the well bore. Calcium scale precipitates faster at high temperature due to reduced solubility. The well fluid is under-saturated with respect to anhydrite. On the other hand it is super-saturated with respect to amorphous silica at temperature below 140°C. When the temperature of the fluid decreases due to pressure drop, the concentration of silica increases in the brine phase. The silica in the brine become more unstable and therefore precipitates as amorphous silica. Sometimes the silica reacts with the available cations such as Fe, Na or Ca to form silicate deposits in the geothermal installations (Ocampo et al., 2005). The well therefore should be operated at temperatures above 160°C to avoid amorphous silica scaling. Figure 12 shows the production aquifer scaling potential of well OW-38A

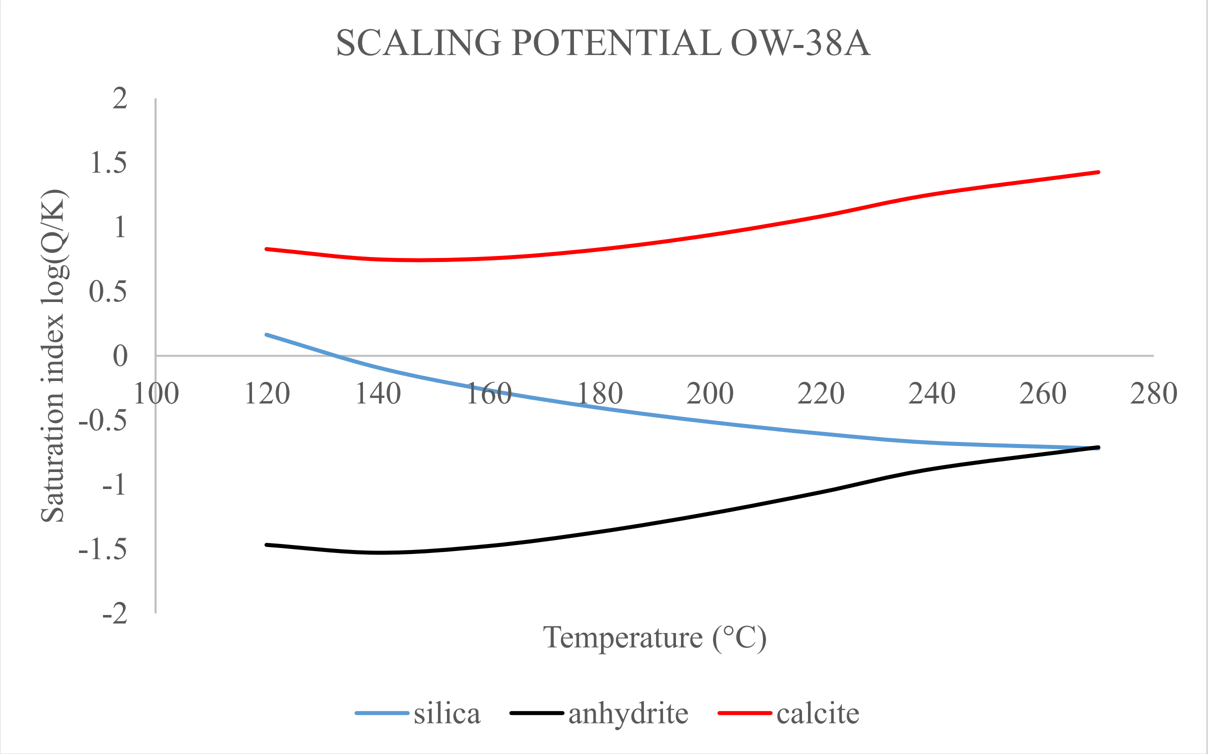


Figure 7: OW-38A scaling potential in production aquifers

7.2 Scaling potential in reinjection well OW-703

The mineral scaling potential assessment was done for the hot reinjection well OW-703 prior to mixing with the condensate. From the simulation results, the well has a potential of precipitating silica at temperatures below 180°C. On the other hand, there is a high risk of calcite scaling in the well at temperatures above 220°C with highest saturation level reached at temperature of 240°C because of the rapid decrease to under-saturation. Boiling increases degassing which produces fluids that are oversaturated with respect to minerals whose solubility decreases with increase in pH (Arnosson et al, 2007). The boiling causes the rapid increase in solubility of calcite. Figure 13 shows the mineral saturation in the well OW-703 in the production aquifers

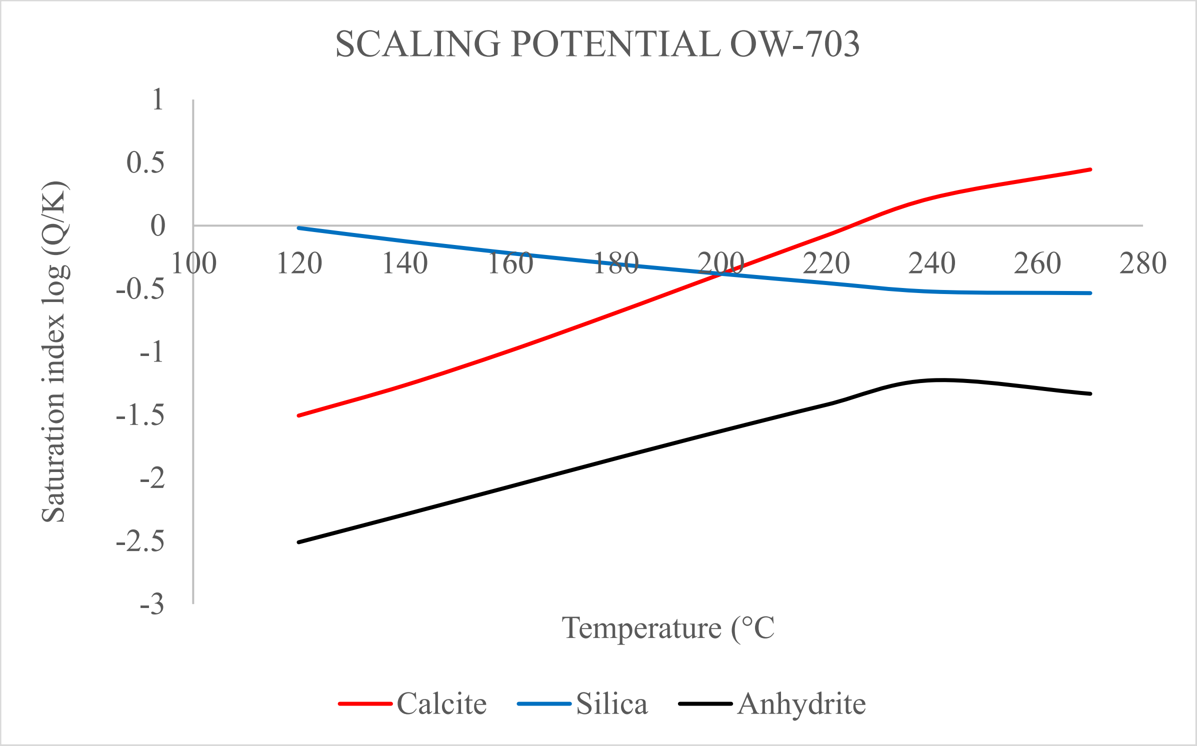


Figure 8: OW-703 scaling potential

7.3 Scaling potential of separated brine and condensate mixtures

The solubility of some scale forming minerals such as calcite, amorphous silica and anhydrite is majorly dependent on the pH. Degassing of water upon boiling affects the mineral saturation state of the scale forming minerals. Scaling is a major threat in any geothermal operations. To try to mitigate this phenomenon, the separated brine and the condensate from the power plant was mixed in various ratios and the possibility of mineral precipitation determined in PHREEQC. The pH and the resultant temperature of the mixtures were recorded. It's important to consider the temperature and pH change during mixing to ensure it is within the permissible reinjection requirement limit that mitigates the scaling and corrosion especially in the cold reinjection wells. From the results of mixing the two fluids, the mixture has potential to precipitate only silica at ratios of 0.5:0.5 and 0.6:0.4 as seen in Figure 14 below. The scaling potential of calcite increases with the increase in the amount of the brine added. Considering the precipitation of the calcite mineral is retrograde, presumably the addition of the brine elevates the temperatures and the calcium concentration, the pH of the mixture is also increases yielding the conducive conditions for the precipitation of the mineral. Below 70% condensate and 30% brine (indicating that the amount of brine is increasing with decreasing amount of condensate), the scaling is significant. This shall be evaluated at later stage at reservoir conditions by boiling the mixtures in WATCH. The anhydrite saturation index is not significantly affected by the mixing and remains fairly stable. The saturation index of amorphous silica seems to slightly increase with the increasing amount of brine in the mixture. This can be attributed to the fact that the brine has high concentrations of silica and therefore with the drastic reduction in temperatures of the mixture, precipitation occurs.

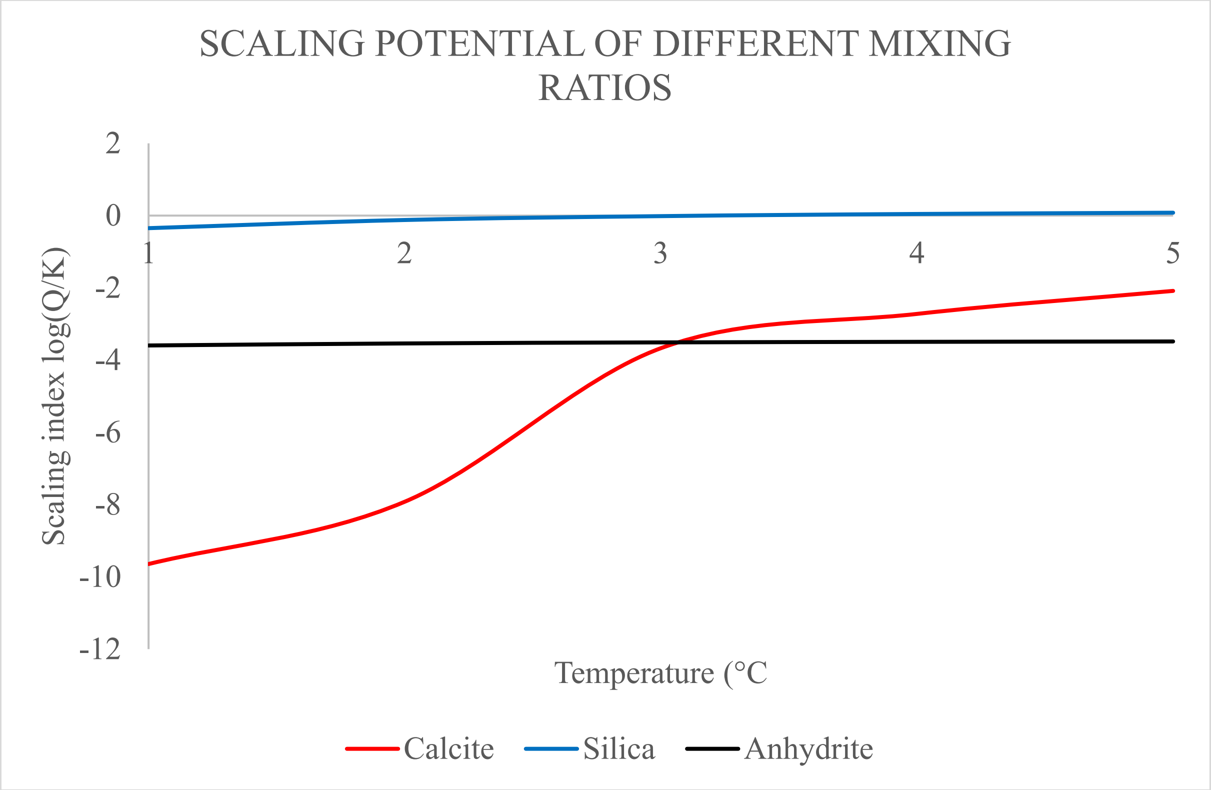


Figure 9: Mineral scaling potential upon mixing in ratios from 0.9:0.1 to 0.5:0.5 before heating up

Increasing the injected separated water proportion in the mixture increases the saturation index of calcite of the mixed fluid.

7.4 Mineral saturation state in reinjection aquifers-effect of fluid mixing

The separated water and the condensate mixture was adiabatically boiled in steps of 20°C from 240°C to 120°C to mimic the reinjection reservoir conditions. The boiling was done in WATCH speciation programme. All the mixing ratios gave temperatures that were less or equal to 100°C and therefore were heated up in PHREEQC before the boiling process. Generally, anhydrite (Figure 15), amorphous silica (Figure 16), and calcite (Figure 17) are under-saturated in the mixed fluid. The saturation index of anhydrite is lowered by increasing the separated water in the mixture as indicated in the Figure 15. Ratio 0.5:0.5 and ratio 0.6:0.4 have a potential to precipitate calcite at temperatures above 180°C as observed in the Figure 17. Increasing the separated water proportion while lowering the condensate proportion in the mixture increases the saturation index of calcite of the mixed fluid upon boiling. On the other hand, amorphous silica scaling potential is increased by the increasing proportion of the separated water in the mixed fluids as observed in Figure 17. The increase in separated water from the OW-703 increases the concentration of silica (total) in the mixture which upon boiling increases the saturation index.

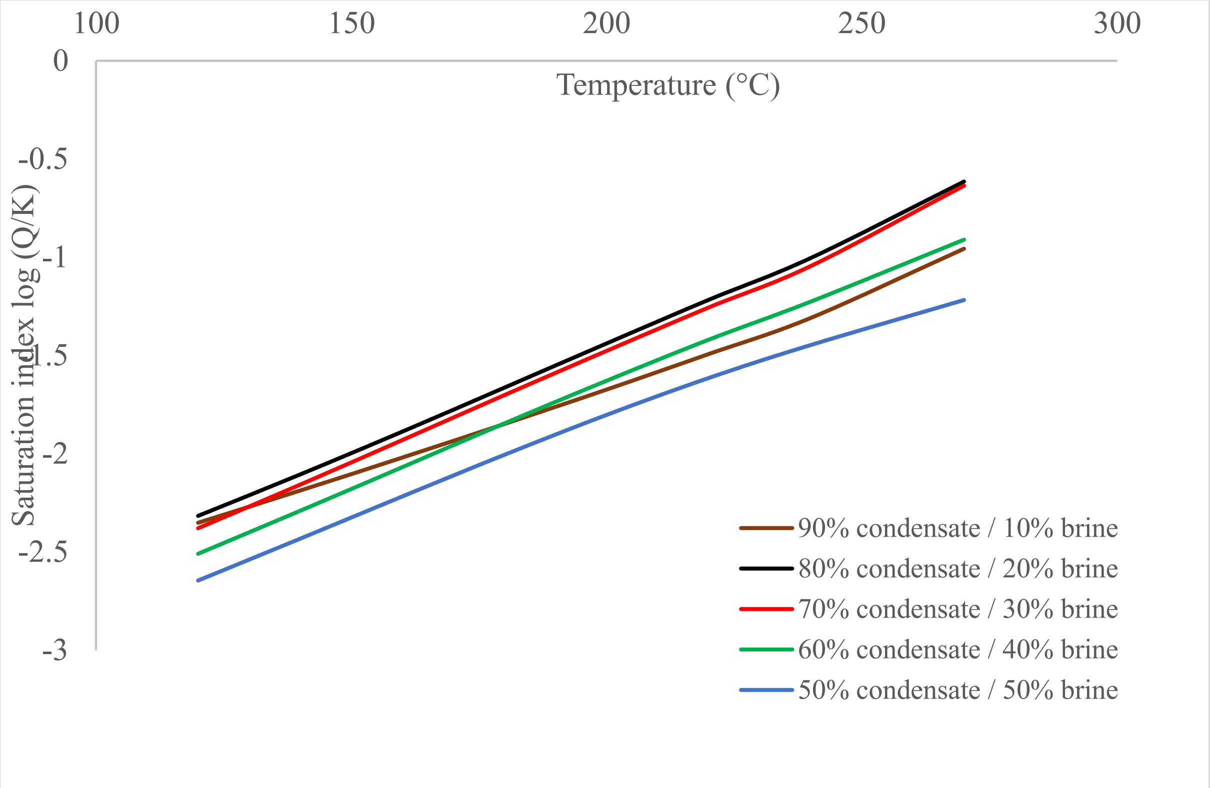


Figure 10: Anhydrite scaling potential of the condensate and separated water mixtures

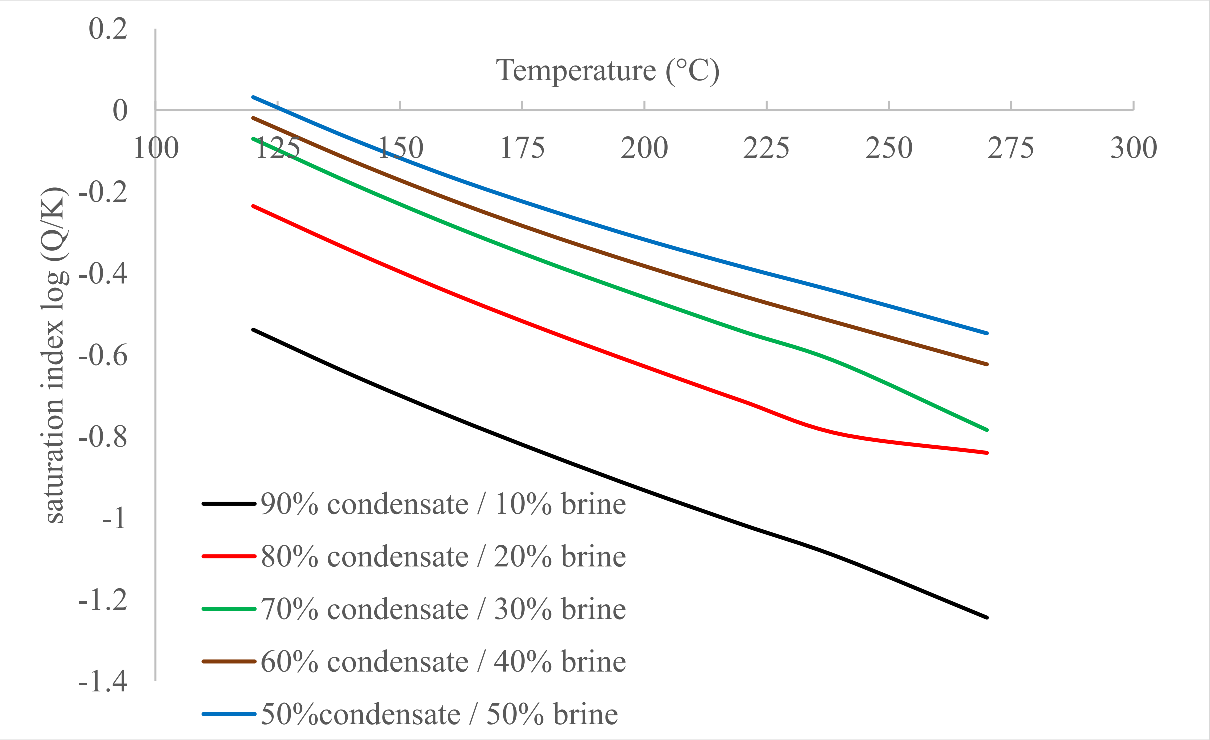


Figure 11: Silica scaling potential of the condensate and separated water mixtures

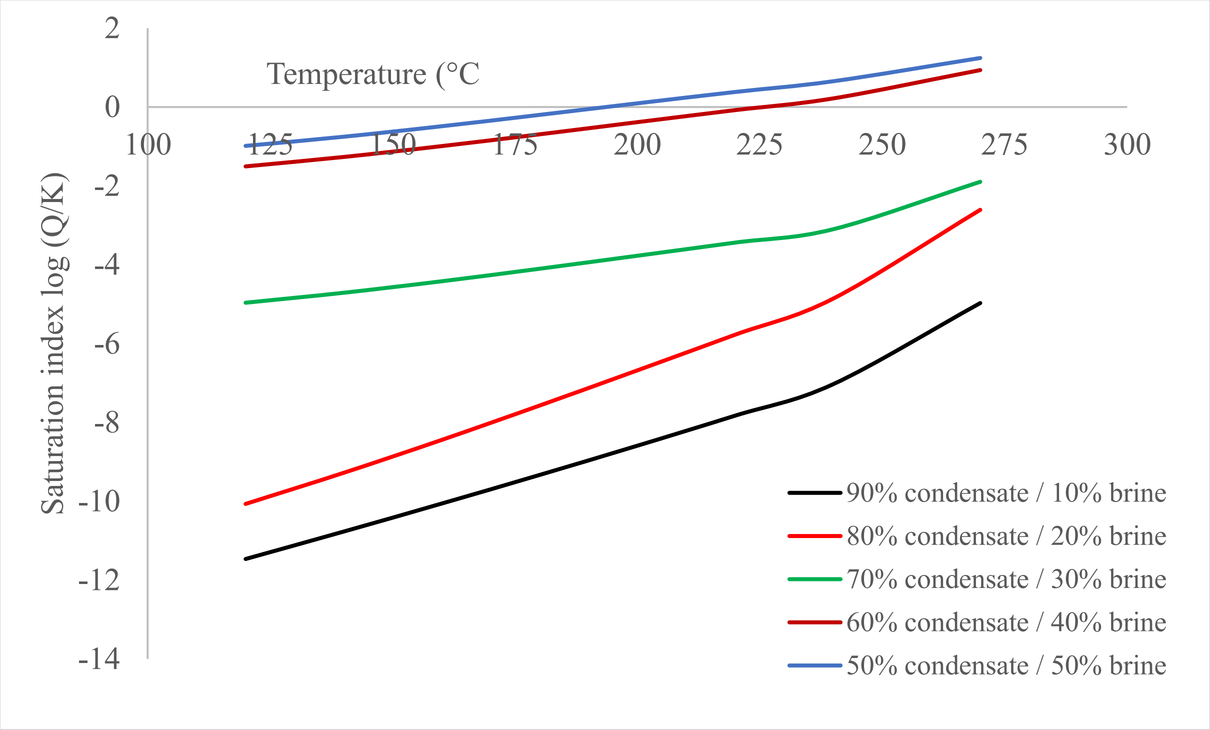


Figure 12: Calcite scaling potential of the condensate and separated water mixtures

Mixing the separated water – condensate mixture with the production well (OW-38A) brine to simulate extreme situations when all the reinjection fluid would replace the deep aquifer fluid during production was done Therefore, the ratio with high potential to precipitate the minerals and the one with less or no potential to precipitate any of the minerals were chosen for this mixing simulations. The two ratios are used for comparison because 0.8:0.2 (80% condensate and 20% separated waters) gave a pH of 3.9 which is considered corrosive to the carbon steel materials used in the power plant and temperature of 67.5°C with no potential to precipitate minerals. On the other hand, 0.6:0.4 gave a pH of 6.5 which is acceptable limit for reinjection practices in Olkaria and temperature of 90.3°C with indications of calcite scaling upon boiling

7.4.1 Scaling potential 60% condensate: 40% separated water mixture

The condensate and brine mixed in the ratio 0.6:0.4 gave a resultant pH of 6.5 and temperature of 90.3°C. To evaluate the scaling tendencies of the fluid once it gets to the reinjection aquifers in the field, the mixture was heated up to a temperature of 240°C in Phreeqc to mimic the reservoir conditions and the output boiled adiabatically in Watch from 240°C to 120°C. The potential of mineral precipitation was evaluated for calcite, anhydrite and silica. Mixing the separated water with the condensate lowers the scaling potential of amorphous silica and calcite in the reinjection well OW-703 as seen in Figure 18 and 19. In the well OW-703 after mixing with the condensate, there is possibility of calcite scaling at temperatures above 220°C.

Generally the scaling potential in the well OW-703 is substantially lowered by mixing the separated water with the condensate from the power plant. In the well OW-38A, mixing reduces the calcite saturation index up to temperature of 220°C above which the saturation index begins to increase seen in Figure 18. Calcite scaling in the well is highest at temperatures above 220°C with SI>1 (supersaturated). From this we can deduce that mixing the production fluid with the separated water - condensate mixture increases the calcite saturation index of the mixed production fluid and diluted brine in the well at temperature above 220°C. The solubility of calcite reduces with increasing temperature and that is why the precipitation increases at this temperature due to increased degassing in the well bore. Therefore, mixing in this case only reduces the saturation index but does not mitigate the scaling in the aquifer. The amorphous silica saturation index in OW-38A increases at temperatures above 160°C in the mixed condensate - separated water and production fluid mixture in the aquifers as observed in Figure 19. A reduction in the saturation index occurs at temperatures below 160°C. This therefore suggests that mixed condensate-separated water can mitigate silica scaling in the well if it is operated at temperatures above 160°C. All the fluids are under-saturated with respect to anhydrite although the mixing raises the saturation index. The anhydrite saturation index increases due to the increased sulphate concentrations in the condensate which further undergoes boiling in the aquifers. Figure 19 and 20 shows silica and anhydrite scaling potential.

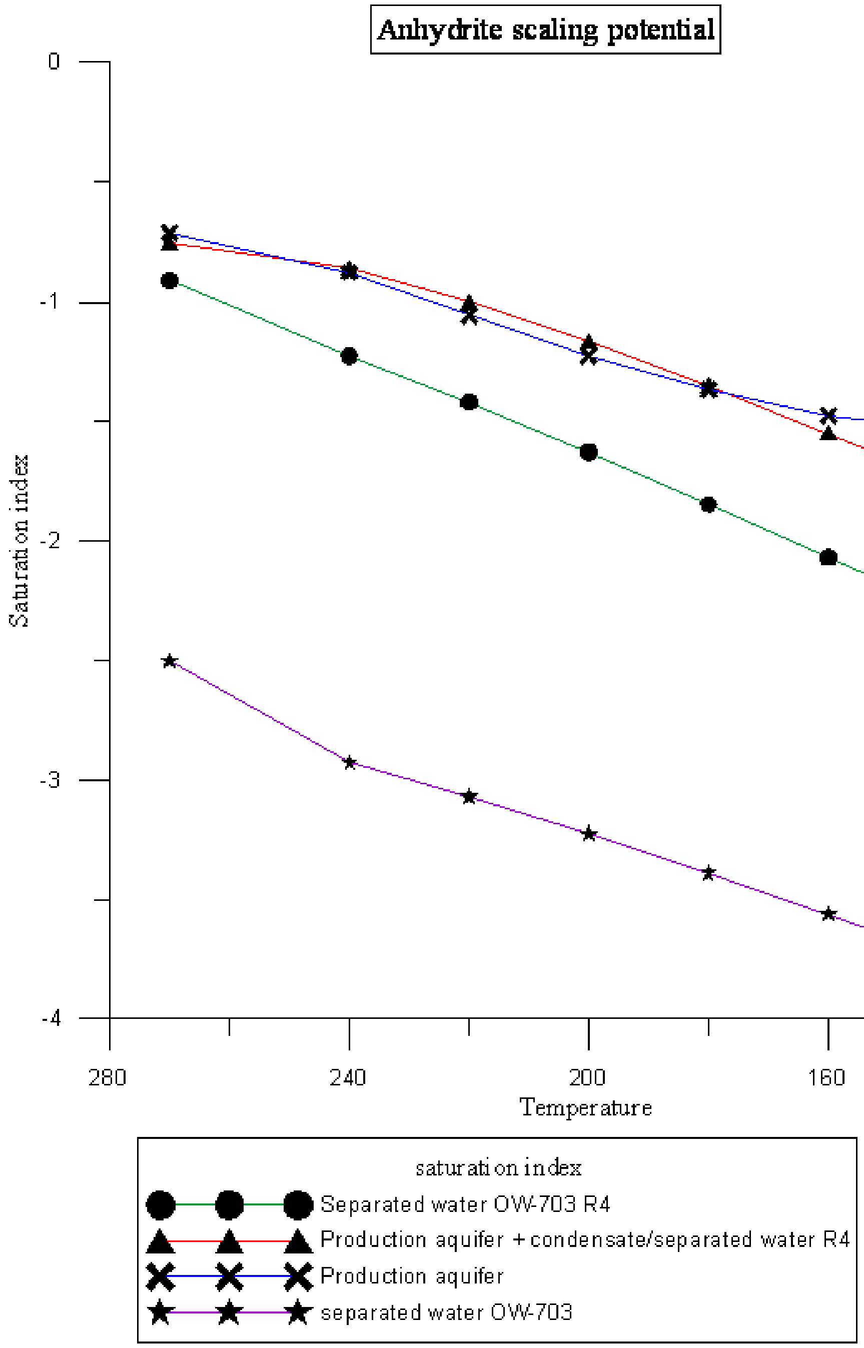


Figure 13: Anhydrite scaling potential as a result of condensate and separated water mixture in production and reinjection aquifers

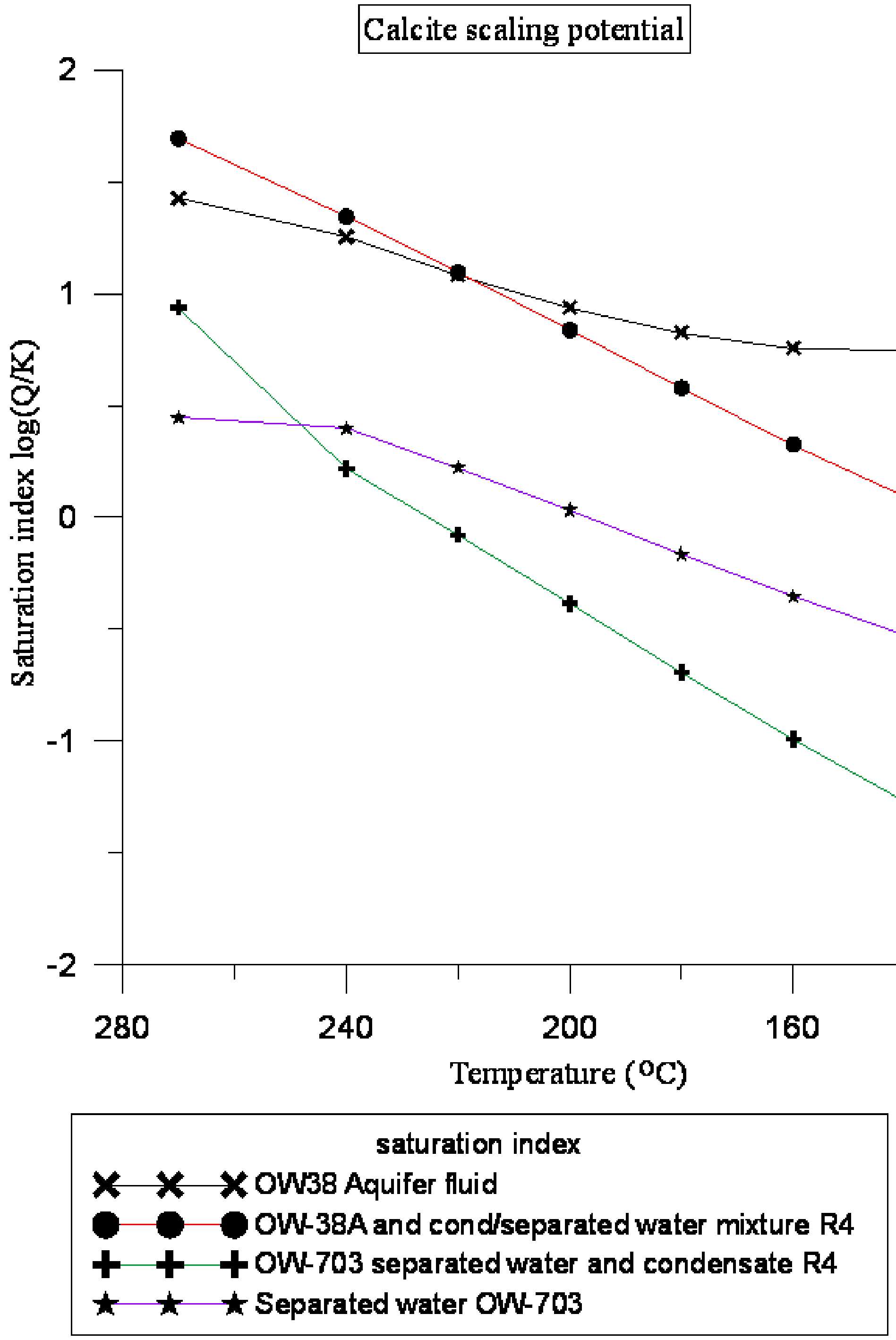


Figure 14: calcite scaling potential as a result of condensate and separated water mixture in production and reinjection aquifers

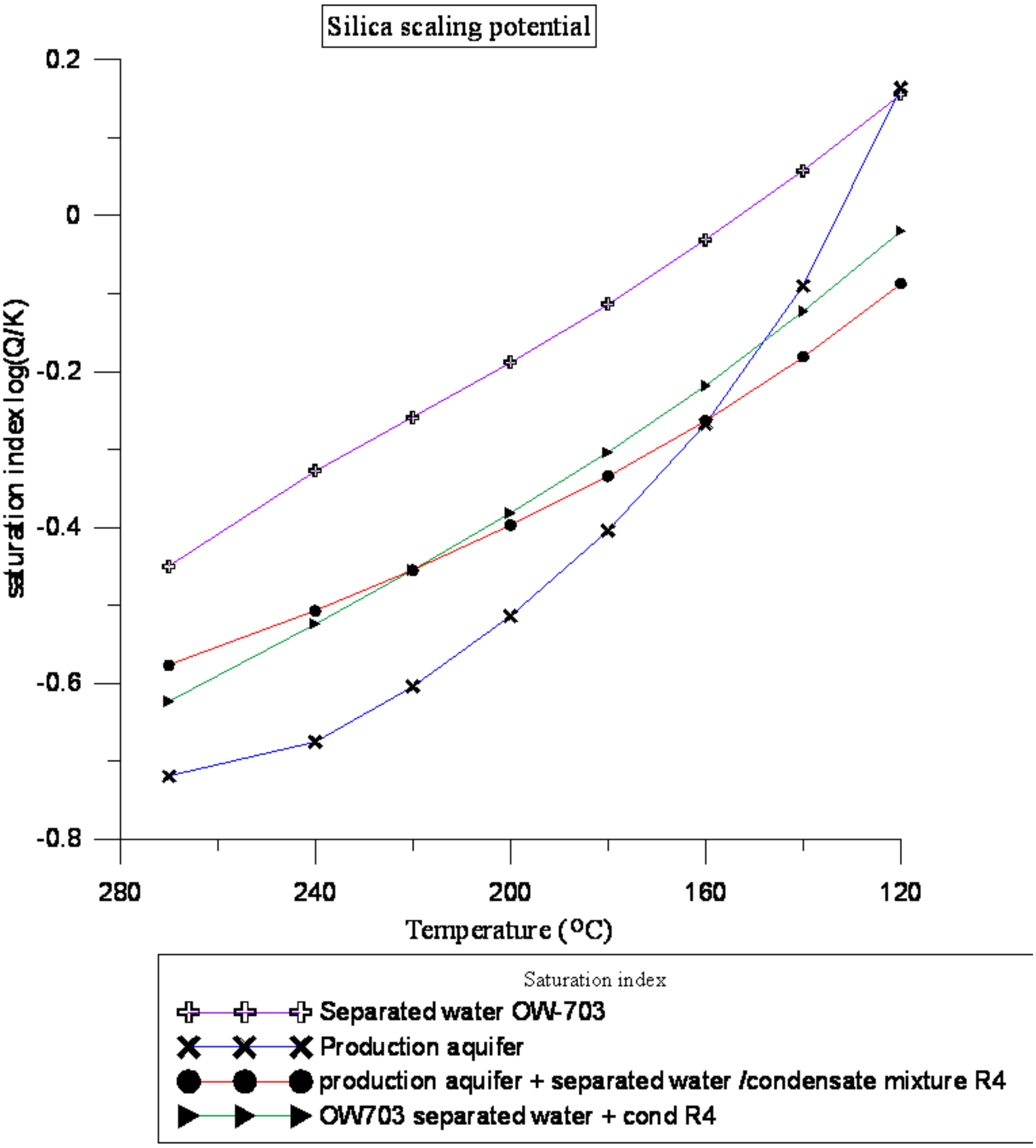


Figure 15: Silica scaling potential as a result of condensate and separated water mixture in production and reinjection aquifers

7.4.2 Scaling potential of 80% condensate: 20% separated water mixture

Simulation was carried out for the mixture of 0.8 condensate and 0.2 separated water. This mixture gave pH of 3.9 and temperature of 67.5°C. The pH is below the required reinjection pH limits in Olkaria which is >6.0. The mixture therefore, was heated up in Phreeqc to 240°C to simulate the reservoir conditions and adiabatically boiled in Watch from 240°C to 120°C in order to predict the scaling potential upon reinjection. The effect of the 80% condensate with 20% brine mixture in the production aquifer was evaluated by mixing it with brine from the production well OW-38A. The OW-703 has a potential to precipitate amorphous silica at temperatures below 160°C as observed in Figure 21. Upon mixing with the condensate, the saturation index of amorphous silica is substantially lower and the separated water – condensate mixture becomes under-saturated with respect to amorphous silica. When the condensate – separated water mixture reacts with the OW-38A fluid, there is increase in the amorphous silica saturation index at temperatures above 180°C. The saturation index then reduces from temperatures below 180°C. This therefore, suggests that the separated water-condensate mixture can only mitigate the scaling in the well if operated at temperatures below 180°C otherwise the scaling risks are increased with the mixed fluid incursion into the production aquifers Both production and reinjection well OW-703 are under-saturated with respect to anhydrite and therefore reinjecting the diluted brine does not pose any danger of anhydrite precipitation. Calcite precipitation will occur when the injected fluid mixes with the fluid in well OW-38A. The mixed condensate and brine provides conducive conditions for calcite precipitation. Calcite, has pH dependent solubility. Solubility of calcite increases with decreasing temperature but decreases with increasing pH. Boiling increases degassing which produces fluids which are oversaturated with respect to minerals whose solubility decreases with increase in pH (Arnosson et al., 2007). The brine from the production well increases the pH and calcium concentration hence it precipitates from the fluid due to over-saturation. Figures 21, 22 and 23 show the mineral saturation state of mixing 80%condensate and 20% separated water

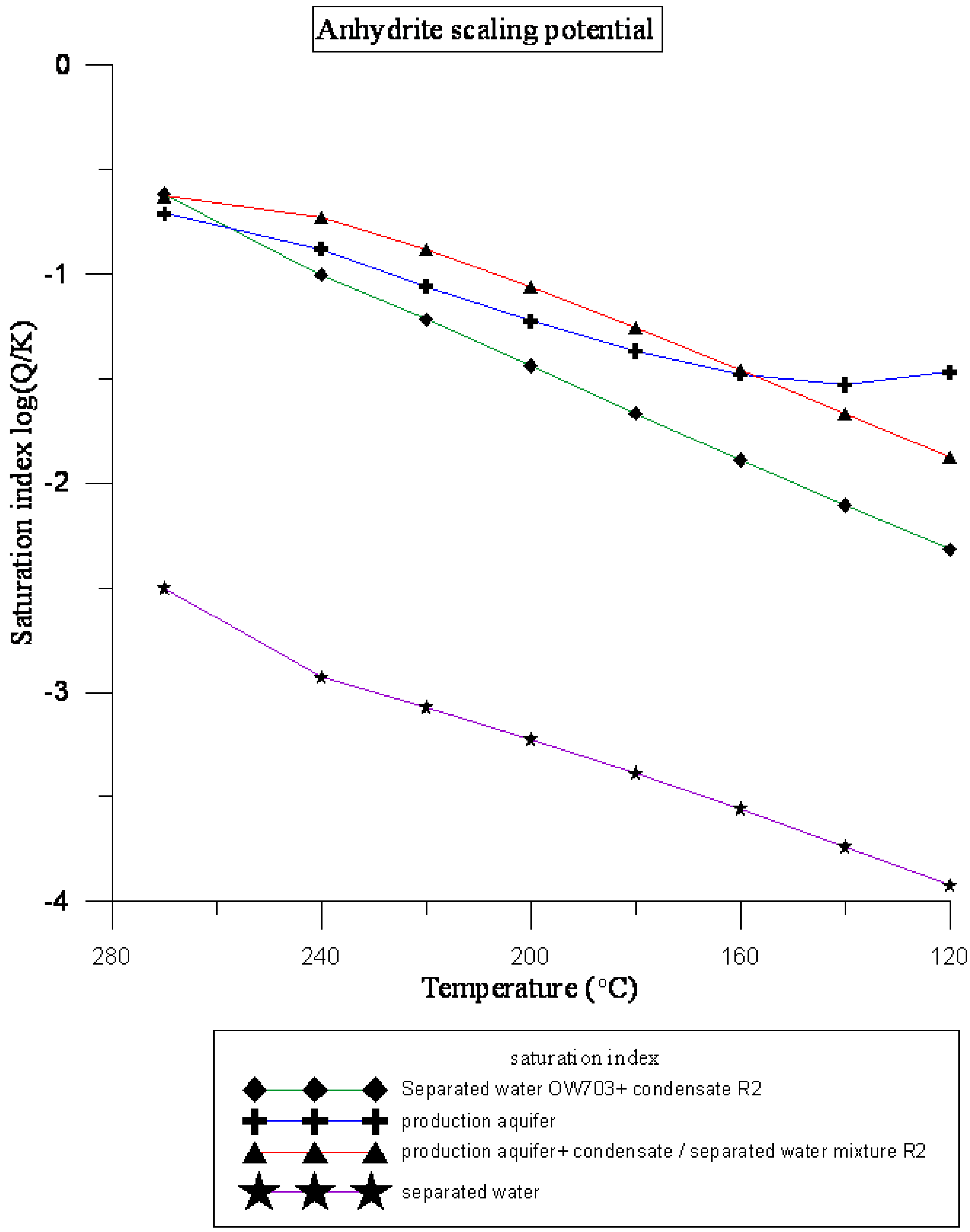


Figure 16: Anhydrite scaling potential as a result of condensate and separated water mixture in production and reinjection

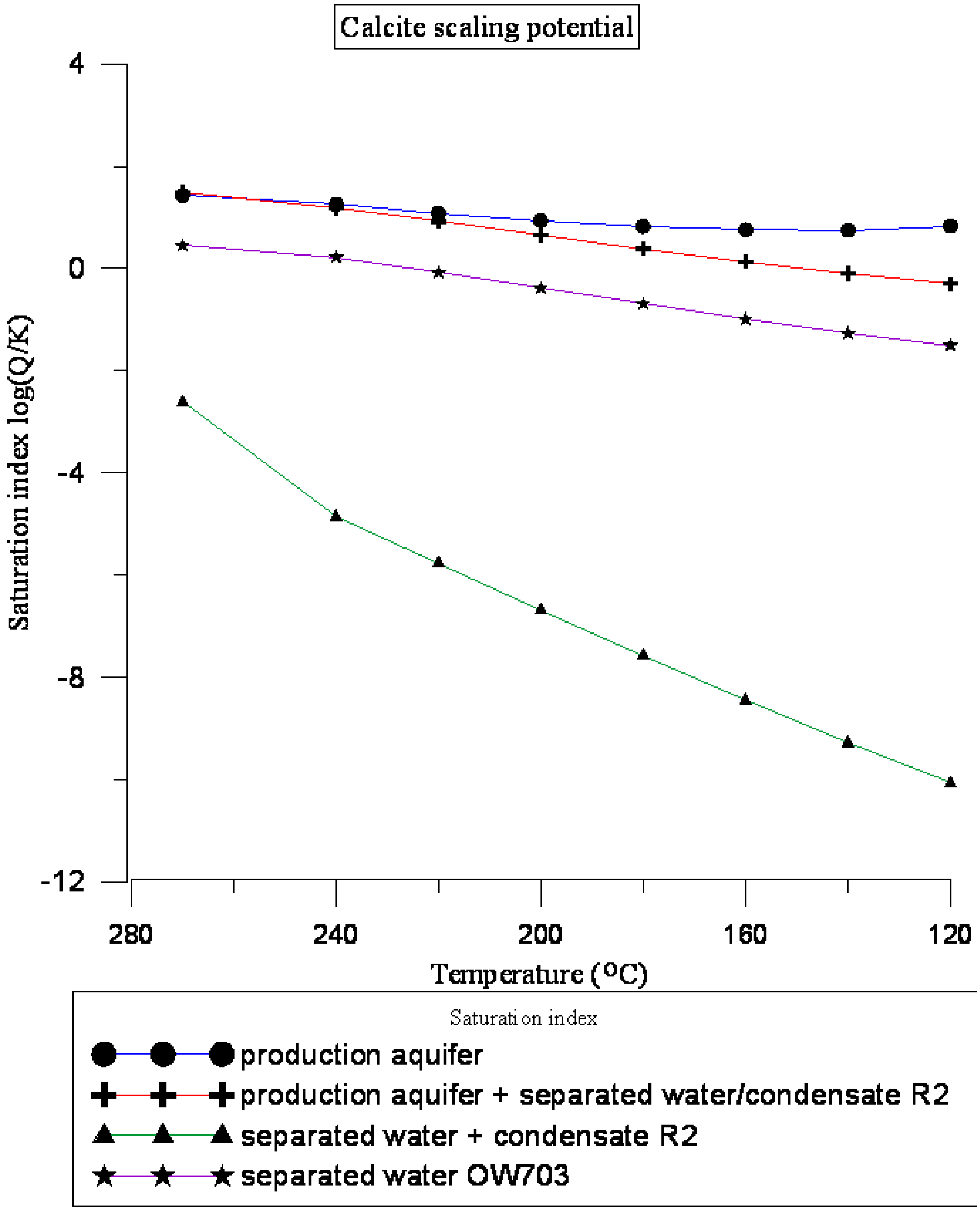


Figure 17: Calcite scaling potential as a result of condensate and separated water mixture in production and reinjection aquifers

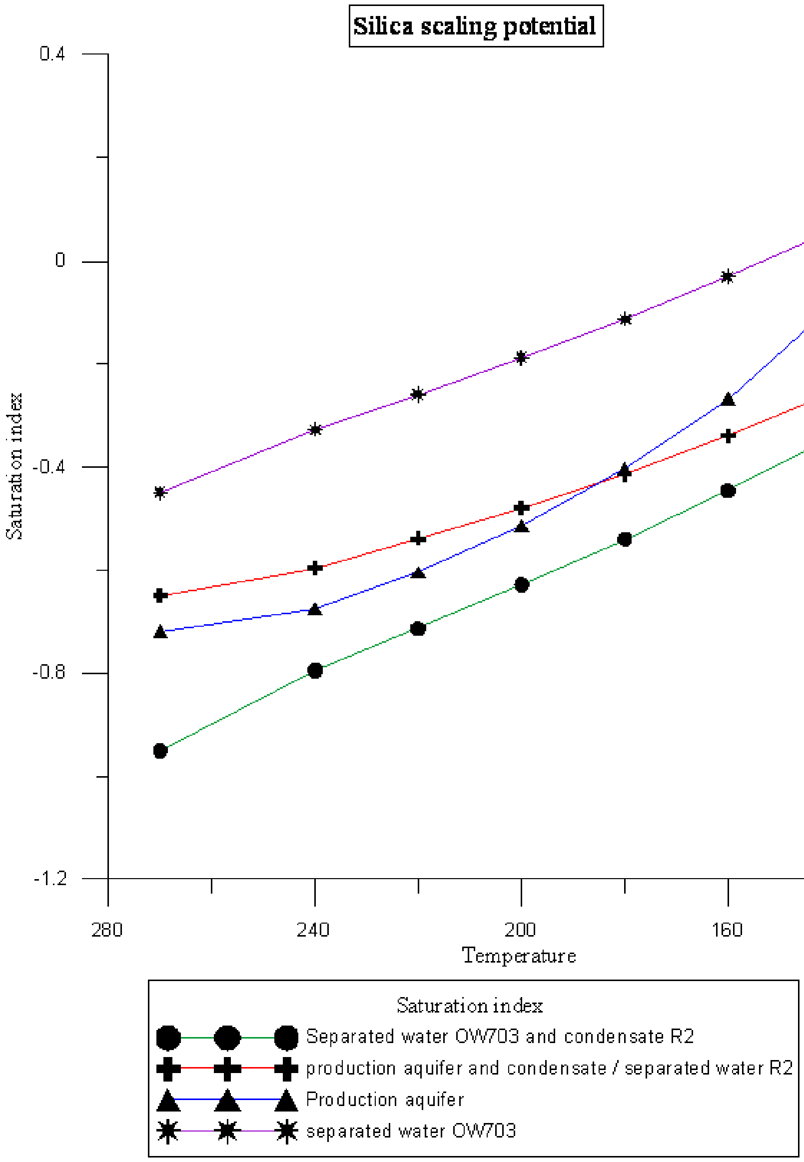


Figure 18: Silica scaling potential as a result of condensate and separated water mixture in production and reinjection aquifers

8. FINANCIAL ASPECT- COST REDUCTION

8.1 Cost of reinjection wells

Olkaria IAU has two cold reinjection wells - OW-801R1 and OW-801R2. Both the wells are drilled to a total depth of 1500 m deep. The time taken to drill one reinjection well of such depth is 30 days (planned) although sometimes can take up to 60 days depending on the challenges experienced like the case of OW-R14 that was planned for 30 days and took 57 days at maximum depth of 1007 m. The cost of drilling was 1.7 MUSD. An average reinjection well in Olkaria would therefore cost between 1.7 to 2 MUSD and an average of 45 days to drill. This project therefore looks forward to minimise losses caused by the severe corrosion and scaling as the costs of the wells are considerably very high. Severe corrosions and scaling can lead to shut in of a well. Scaling such as amorphous silica and calcite can clog the permeable locations reducing the water percolation rate into the formations. This project therefore, will reduce the possible challenges brought about by the scaling and corrosion issues in terms of minimising the cost of drilling or repairing a well and the amount of soda ash used in the power plants.

8.2 Soda ash requirement

The amount of soda ash is reduced in that, only the cooling tower water will be dosed with the sodium carbonate while the reinjection fluid, since it will be mixed with the brine to elevate the pH will leave the power plant at the pH of the circulating water. The amount of soda ash required for the Olkaria IAU power plant is 35 bags each 50 kg (1750 kg). For cooling tower basin water one unit required 4 bags each 50kg (200 kg) for the two units in Olkaria IAU, 400 kg of soda ash per day is required to raise the pH to 4 if directly injected. This therefore means that reinjection water alone requires 27 bags per day.

1 tonne of standard grade soda ash = 283.48 USD

1 bag of standard ash soda ash = 14.17 USD

27 bags of standard ash =382.70 USD

Amount saved per annum = 64,293.264 USD/ annum/ plant

9. SUMMARY

- Olkaria East production field discharges dilute sodium chloride water with high chloride content of 200-350 ppm. The bicarbonate content of the field is below 1000 ppm while the CO2 concentration in the field is 10000 ppm in the western part and 10 ppm and below in the eastern part of the field. The average temperature according to Na/K and quartz geothermometers is 230-260°C;
- Olkaria I additional unit power plant has two units both with varying chemistry. This is because they are fed by steam from different separator stations. Unit 5 seem to have carry overs as indicated by the high sodium and silica concentrations. Mixing condensates from these two units result in overall increase in silica, sodium and CO2 concentrations in the resultant condensate;
- OW-703 has calcite scaling potential at temperatures above 220°C and silica scaling at temperatures below 180°C. the well therefore need to be operated at temperatures that will lower the scaling potentials of the two minerals;
- OW-38A, used as a representative well for the production field has high potential for calcite scaling and may precipitate silica at temperatures below 140°C;
- Mixing the condensate and separated water may result in silica precipitation if mixing ratio is lowered below 70% condensate and 30% separated water.

10. CONCLUSION

The assessment of the scaling potential in the production aquifers before production in the well OW-38A shows that the fluid has a potential to precipitate calcite. The condensate – separated water mixture only reduces the saturation index of silica and calcite at certain temperatures but does not completely mitigate the scaling in the wells. The mixture lowers the scaling potential at temperatures below 160°C above which the saturation index for calcite and silica increases in the production aquifers.

Reinjection well OW-703 reaches over-saturation with respect to silica at temperatures below 160°C. The well therefore needs to be operated at temperatures above 160°C which is above the amorphous silica saturation temperatures to mitigate scaling in the well. The well has a potential to precipitate calcite at temperatures above 160°C with highest saturation state at above 220°C after which there is rapid decrease to under-saturation with respect to calcite. This is because boiling causes degassing and rapid increase to solubility of calcite. OW-703 requires to be operated at minimum temperature of above 160°C to mitigate the possible scaling in the well;

Injecting the separated water – condensate mixture in the reinjection aquifers lowers the scaling potential for calcite and silica substantially. Increasing the separated water proportion in the mixture increases the calcite and silica saturation indices. Mixing the condensate and separated water substantially lowers the scaling potential of calcite and silica when the proportion of the condensate is kept higher than the separated water proportion. 70% condensate and 30% separated water will be ideal proportions for mixing the fluids. On the other hand, saturation index for anhydrite is increased but does not pose any major challenge because it still remains under-saturated;

The most ideal mixing ratio is the 60% condensate and 40% separated water because it mitigates both the scaling in the reinjection well bore and also prevents corrosion by raising the pH of the fluid. Initially the pH of the condensate from the condenser is at 2.5 and temperature of 45°C, when mixed with the separated water, the resultant pH is 6.8 and temperature of 90.3°C. The pH meets the limit for reinjection required for Olkaria fields for the cold reinjection. This method therefore can be a solution to pH modification instead of the current chemical dosing.

11. RECOMMENDATIONS

- Further simulations including more reinjection and more production wells need to be carried out with inclusion of condensate from other plants due to distinct chemistry in the plants;
- The modelling should include design aspects especially in Olkaria where cold reinjection is done at the periphery of the production field;
- Financial aspects need to be considered for the project considering the changes in design of the condensate pipeline

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