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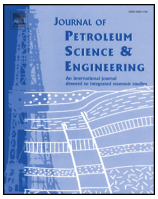

Kaolinite fines colloidal flow in high temperature porous carbonate media during saline water injection

B. Kanimozhi[a], Vivek Thamizhmani[b], Venkat Pranesh[c,*], S. Senthil[d], Arun Selvakumar T.[e]

[a] Sathyabama Institute of Science and Technology, Chennai, Tamil Nadu, India
[b] Vels Institute of Science, Technology & Advanced Studies, Chennai, Tamil Nadu, India
[c] Dawn Calorific Exports, Chennai, Tamil Nadu, India
[d] Kamaraj College of Engineering and Technology, Virudhunagar, Tamil Nadu, India
[e] Santhiram Engineering College, Kurnool, Andhra Pradesh, India

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ABSTRACT

Kaolinite clay fines are prevalent in sandstone porous media and it has great impacts on permeability and well productivity decline. High temperature sandstone formations detach the fines from the pore surface and migrate along with the permeating fluid. At some point the fine particles are strained in the pore throats, which leading to permeability damage and well productivity decline. To the best of our knowledge this phenomenon is not well explored in the high temperature carbonate media. Since most of the world's oil reserves are held in carbonate media and its worth to explore the formation damage, especially due to fines migration during higher reservoir temperature at these formations composed of carbonate minerals. Hence, this paper presents laboratory modeling of kaolinite fines colloidal flow in high temperature porous carbonate media during saline water injection. In this paper, we have conducted three sets of coreflood experiments in the temperature ranges of 100 °C 150 °C, and 200 °C. Kaolinite suspension water has been injected into the porous limestone core at these temperature regimes to investigate the possibility of permeability and injectivity deterioration. The main experimental results showed there is an increase in water saturation and heat transfer rates. Concentration of fines surges with increasing PVI and permeability declines with increasing time. Pressure elevates with enhancing PVI, but it plummets after some time. Significantly, the water discharge rate declines for increasing suspension injection and on the other side, for fresh water injection, the rate of water discharge rises steadily. Furthermore, the electrical and thermal conductivities of effluent kaolinite colloid were higher. Moreover, experimental model were tested against statistical based optimizational model, response surface methodology (RSM). These results revealed good agreement and, hence, this paper has explicated the importance of kaolinite clay fines suspension transport in high temperature carbonate reservoirs.

1. Introduction

Almost 60% of global oil reserves are located in carbonate reservoirs and, especially, the Middle East regions are highly governed by carbonate oil fields, which approximately 70% oil reserves are loaded in these reservoirs (Yang et al., 2018; Schlumberger, 2007). Wettability alteration and low salinity waterflooding is the prime focus in the development of improved oil recovery in carbonate reservoirs (Sharma and Mohanty, 2013, 2018; Mahani et al., 2015; Al-Attar et al., 2013; Nasralla et al., 2018). There are many articles dealing with these areas in several scientific archives. For instance, Chandrasekhar et al. (2018), analyzed the wettability dependence on brine composition in high temperature carbonate rocks. The authors have conducted low salinity flooding in limestone cores at high temperatures and this was performed to understand the ion behavior at brine/rock interactions. They also developed a surface complexation model to understand the reactions and mechanism occurring during coreflood experiments. It was revealed in their results that during seawater injection there is an exchange of ions and this helps in the effective oil displacement and recovery. Xiao et al. (2018), evaluated the low salinity waterflooding in Middle East carbonate reservoirs using a new field-representative coreflood method. The authors have conducted both conventional unsteady state and newly developed low salinity coreflood experiments. Mainly, wettability alterations were observed in some cases and this indicates a potential of low salinity water flooding in Middle East Carbonates. The novel coreflood method can accurately capture the

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[*] Corresponding author.
E-mail address: venkat.pranesh@yandex.com (V. Pranesh).

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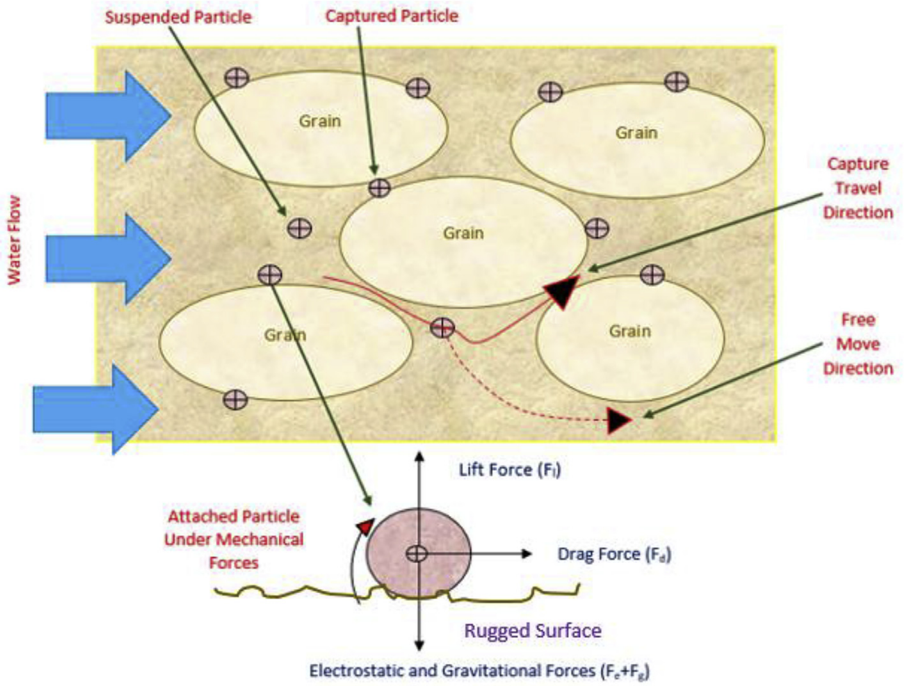

Fig. 1. Schematic diagram of fines behavior in carbonate porous media.

effects of wettability. Also, the reduction in the viscosity of low salinity brine deteriorated the oil recovery upsurge.

On the other side, fines migration in carbonate reservoirs are becoming a serious problem and it possess a great threat to well productivity. Fines are in-situ tiny mineral and clay particles such as quartz, kaolinite, illite, montmorillonite, etc. But, this paper only explores the fines migration in high temperature porous carbonate rocks as a function of kaolinite clay. Typically, kaolinite is predominant in sandstone rocks since these rocks contain quartz and feldspar. Kaolinite occurs in sandstone rocks upon the dissolution of feldspar at extreme temperature and geochemical alterations. Generally, carbonate rocks are poor in clay minerals and kaolinite comprising carbonate rocks shows higher grain density than other clay containing rocks (Aoyagi and Chilingarian, 1972). Earlier itself clay minerals, especially kaolinite are discovered in certain carbonate oil reservoirs, for example, Bombay High Oil Field in India during 1981 (Rao, 1981).

Derkani et al. (2018), studied and reviewed the fines migration mechanism in carbonate reservoirs during low salinity waterflooding. The authors specifically analyzed the interfacial mechanisms that dominate the oil transport and recovery in porous carbonate rocks. Interestingly, it was revealed from their review that migration of fine particles can assist in enhancing the condition of the water-wetness. A detached and transported particles can potentially barricade some pore throats and thereby diverting fluid flow and increasing the microscopic sweep efficiency, while damaging the permeability. Overall, fines transport can lead to an enhancement in carbonate rock water wetness condition. Sazali et al. (2018), analyzed the fines migration during CO_2 saturated brine flow in carbonate reservoirs along with some displacing clay minerals. The authors have conducted this study in a high CO_2 carbonate gas field at offshore, Sarawak, Malaysia, which is scheduled for development. Initially, the authors considered that fines migration in general not a serious formation damage problem in a typical carbonate formation. However, the authors conducted a serious of coreflood experiments for examining the fines migration and came to a conclusion that fines migration in carbonate rocks can be a serious issue, which is essential and worthy of consideration. Additionally, they indicated that fines migration would trigger a formation damage problem during the later stages of production that is when the water production from the reservoir start to increase.

Qajar et al. (2013), examined the fines migration effects on the porosity of carbonate rocks. Actually, the authors have studied the reactive flows in carbonate rocks accounting for chemical dissolution and fines migration. They have used micro-CT scan for detecting the porosity and permeability changes in carbonate rocks due to acidification and especially, fines blockage. It was found from their research that there was a significant variation in carbonate pores mainly due to fines plugging. It can be explicitly stated that even carbonate reservoir rocks are highly prone to formation damage due to fines migration, reactive flows, and geochemical alterations. This paper explores the feasibility of kaolinite fines colloidal flow in high temperature carbonate rock. For this purpose, a laboratory based investigation was conducted to examine the suspension flow and injectivity decline. To the best our knowledge, there are limited work on fines migration in carbonate rocks and no work on kaolinite fines transport in high temperature carbonate rocks. Therefore, this paper may be a platform or benchmark in quantifying the kaolinite penetration in high temperature porous carbonate media during high and low salinity water injections.

1.1. Problem and mathematical formulation

This section presents problem and mathematical formulation for single phase flow (water) and fines mobilization in high temperature porous carbonate media as a function of surface roughness and kaolinite clay fines. Commonly, fines have a size of the order 1 μm and a net surface charge (Raha et al., 2007). Furthermore, fines are held in porous rocks under the influences of four forces namely, lift (F_l), drag (F_d), gravity (F_g), and electrostatics (F_e), as shown in Fig. 1. The gravity and electrostatic forces hold the fines to the pore surface (Zeinijahromi et al., 2016) and it should be noted from this figure that a fines particle is held over a rugged surface. According to Narasimhan (2012), there is continuous and high degree of heat flow in porous media and this has an impact on the mass balance and transfer in porous media. So this heat flow will affect the mechanical stability of the in-situ porous fines and tend to oscillate and collided with pore walls that subsequently losing the particle momentum (Kampel, 2007). Additionally, the higher heat flow in porous media from geothermal gradient reduces the electrostatic forces of the rock and subsequent, the fines will detach from the rock surface and tend to migrate along the direction of heat or else with the permeating fluid (Pranesh and Ravikumar 2019; You et al., 2016). Fines rapid detachment under higher reservoir temperature is a usual and bewildering occurrence (Schembre and Kovscek, 2005) and this is a leftover hypothesis that need to be investigated in the reservoir formation damage area. It can be seen from Fig. 1 that the detached fines are migrated in the carbonate porous interspace and some fine particles are captured in pore-throat and moreover, there are fines which are freely moving under the impetus of heat or fluid or combination of both. The fine and fluid mobilization may be slow due to its movement on the rugged surface, which reduced the speed and time of the flow rate.

We formulate a simple mathematical framework for this scenario. Generally, heat flow and transfer is the root cause for fines detachment and transport in porous carbonate rock layer. So that first we shall write down 1D, 2D and polar-coordinate heat flow equations:

$$\frac{\partial u}{\partial t} = \alpha^2 \frac{\partial^2 u}{\partial x^2} \tag{1}$$

$$\frac{\partial u}{\partial t} = \frac{K}{c}\left[\frac{\left(\frac{\partial u}{\partial x}\right)_{x+\delta x} + \left(\frac{\partial u}{\partial x}\right)_{x}}{\delta x} + \frac{\left(\frac{\partial u}{\partial y}\right)_{y+\delta y} + \left(\frac{\partial u}{\partial y}\right)_{y}}{\delta y}\right] \tag{2}$$

$$\frac{\partial^2 u}{\partial r^2} + \frac{1}{r}\frac{\partial u}{\partial r} + \frac{1}{r^2}\frac{\partial^2 u}{\partial \theta^2} = \frac{1}{\alpha^2}\frac{\partial u}{\partial t} \tag{3}$$

The energy equation for both solid and fluid phase in elemental volume of the porous medium (Nield and Bejan 2013), we have:

$$(1-\varphi)(\rho c)_s \frac{\partial T_s}{\partial t} = (1-\varphi)\nabla.\,(k_s \nabla T_s) + (1-\varphi)q_s^{'''} \tag{4}$$

$$\varphi(\rho c_P)_f \frac{\partial T_f}{\partial t} + (\rho c_P)_f v.\,\nabla T_f = \varphi\nabla.\,(k_f \nabla T_f) + \varphi q_f^{'''} \tag{5}$$

s and f terms for solid and fluid phases

Then, the Darcy model of momentum balance for the fluid is represented as below (Vadasz, 2016):

$$V_* = -\frac{k_*}{\mu_*}[\nabla_* \rho_* - \rho_* g_* \hat{e}_g]$$

where, $\hat{e}_g$ is unit vector in the gravity acceleration. Next fines mass balance equation over a rock surface is given by (Yang et al., 2016; You et al., 2016):

$$\frac{\partial(\phi c + \sigma_s + \sigma_a)}{\partial t} + U\frac{\partial c}{\partial x} = 0 \tag{6}$$

where,

$\sigma_s + \sigma_a = Concentrations\ of\ attached\ and\ strained\ fines,\ U$
$= Darcy\ velocity,\ c$
$= Volumteric\ concentration\ of\ suspended\ particles,\ t = time,\ \phi$
$= Porosity\ and,\ x = Distance$

The intermolecular forces acting between two fine particles over rock grain, like in Fig. 1 can be written as follows (Raman et al., 2016):

$$F_i = \frac{\partial}{\partial_j}(\rho C_s^2 - P)\partial_{ij} + k\rho\frac{\partial}{\partial x_i}\frac{\partial^2}{\partial x_j}\frac{\rho}{\partial x_j} \tag{7}$$

The wettability is an interaction between rock-vapor surface tension, γ_{sv} and rock-liquid surface interfacial tension, γ_{sl}. The general measure of contact angle for liquid and solid particle is given by the Young's equation (Alshakhs and Kovscek, 2016):

$$\gamma_{lv}\cos\theta = \gamma_{sv} - \gamma_{sl} \tag{8}$$

And an EOS for interfacial tensions can be written as (Yuan and Randall Lee, 2013):

$$\gamma_{sl} = f(\gamma_{lv}, \gamma_{sv}) \tag{9}$$

Additionally, Gibb's Thermodynamics of Wetting states that the interface between solid and fluid phase can be split into two parts, one fitting to solid and the other belonging to the fluid. Consistently, the interface forming work can be mentioned as the total work (ω) of forming solid surface in a vacuum and the forming work (ρ) of the fluid part of the interface. The quantity (ρ) called by Gibbs superficial tension of a fluid in contact with the solid. This can be treated as energy or as a force like the liquid surface tension (Toshev, 2006). The Gibbs solid-liquid adsorption equation is given by:

$$d\omega = -S_s dT + (\sigma - \omega)\,{}^{dA}\!\big/_{A} - \sum_i \Gamma_i d\mu_i \tag{10}$$

Geological fabric theory describes the spatial and geometric configuration of rock texture which includes surface roughness, cleats, cracks, fissure, and fractures (Hobbs et al., 1976). In reality, all reservoir porous rocks are fabric in nature and to be specific, its pore walls has fabric design (Hills, 1963; Davis et al., 1942; Fossen, 2010; Beddiar et al., 2005). Its major types are primary, shape, crystallographic, S-fabric, L-fabric, and penetrative fabric (Twiss and Moores, 2007). Additionally, Oliveria et al. (2014) and Yang et al. (2016) reported slow mobilization of reservoir fines and fluid over rock surface having fabric surface texture. For rough surface there is a rate of change of surface free energy that is given by Frenkel's approach:

$$\frac{dF}{dt} = 2\pi\gamma_{1v}[cos\theta - rI]r_o v_E \tag{11}$$

During continuous flow of fluid and particle over rugged rock surface there will be a decline in fluid velocity due to high intensity of surface roughness (linear and continuous variation in the surface). Because of rugged surface, there will be a high thermal conductivity and this may dictate the slow mobilization of fluid. Generally, surface roughness (R_∇) can be measured with Taylor Hobson tester. Henceforth, rock surface fabrics with thermal conductivity determines the particle wettability and slow mobilization in porous media (Wu et al., 2016). Therefore, the wettability of fines particle over rough surface is mention as:

$$\theta = cosh\rho gd\sqrt{\frac{y_1 + y_2 + y_3 \ldots\ldots y_n}{n}} \tag{12}$$

where,

$\theta = contact\ angle,\ h = height,\ g = gravity,\ d = density,\ \rho$, and
$= density,\ and\ n = total\ number\ of\ ordinates$
$y_1 + y_2 + y_3$ = distance between the ordinates that is the rock teeth.

After that, the heat of immersion in carbonate media with taking surface roughness (R_∇) into an account can be mentioned as:

$$\cos\theta = \frac{R_\nabla\left[\frac{dR_\nabla(\gamma_{lv}cos\theta)}{dT} - \Delta H_i\right]}{\gamma_{lv}} \tag{13}$$

The net work done by heat flow to liberate the fines from rock surface

$$\eta_{\phi R} = \frac{W_R}{Q_\Omega} \tag{14}$$

where,

$\eta_{\phi R} = Thermal\ efficiency\ of\ porous\ media\ with\ regards\ to\ radiation,$ W_R = Net work transfer to migrate the reservoir fines in porous media, and Q_Ω = Heat transfer to porous media.

$$\eta_{\phi R} = \frac{\frac{\gamma}{\gamma+1}\cdot\frac{\Delta p}{q_w}\left[\left(\frac{T_{Kh}}{T_{Ki}}\right)^{\frac{\gamma+1}{\gamma}} + 1\right] + \zeta_{\mathrm{e}}}{Q_{\Omega}} \tag{15}$$

where,

$$\zeta_{\mathrm{e}} = \lambda.\ \mathrm{F}\left(\frac{r}{\mathrm{A}}\right)$$

Where, $\mathrm{W_R}$ = Total work done (heat rejection) to displace all fines in pore surface and for migration in porous space, γ = Continuous heat rejection to porous media from rock surface (without any interval), 1 = Constant term for additional time which indicates heat transfer rate for every second, Δp = Change in pressure inside porous media, T_{Kh} = Final and highest thermal conductivity of rock surface, and T_{Ki} = Initial thermal conductivity of rock surface.

The slow mobilization of fines with respect to rock surface roughness is mentioned as

$$Q_{K\sigma} = R_{\nabla}(t_2 - t_1)\left(\frac{K_1 + K_2}{2}\right)\left(\frac{t_1 - t_2}{r_2 - r_1}\right) \tag{16}$$

Actually, this equation accounts for a fine particle slow movement with regards to change in the rate of heat flow and thermal conductivity. Fluid flow decline on the basis of fabric theory

$$t_q = -\frac{1}{\beta} + \sqrt{\left(\frac{1}{\beta} + T_w\right)^2 - \frac{Q_d r_1^2}{2\beta K_0}\left[\left(\frac{r}{r_1}\right)^2 + 2ln\left({}^{r_2}\!/_{r}\right) - \left(\frac{{r^2}_2}{2}\right)^2\right]} \times R_{\nabla} \tag{17}$$

where, β = *Formation damage coefficient*

The above equation is equated with time and the overall goal of sluggish fines analysis is to provide the time and the speed of the fluid and particle mobilization. equation (17) indicates the development of heat with the porous interspace with presence of surface roughness. Collectively, these process will lead to a reservoir formation damage. Therefore, a simple mathematical formulation was applied for a fine particle in carbonate porous rocks and the subsequent sections explores the experimental modeling of this scenario.

2. Materials and methods

This section presents the material and methods that were used in this research work. As mentioned earlier that this is a laboratory based analysis and for that, we have acquired a limestone core of length 20 cm and in 5 cm diameter. The core is having a porosity of 28% and 200 mD. Fig. 2 shows a schematic diagram of the experimental setup. It can be seen from the figure that the limestone core is placed in a stainless steel cylindrical core holder and in turn placed inside the oven. The oven is attached with a thermocouple and three pressure gauges (for measuring the pressure difference across the core). One pressure gauge is connected to the inlet and outlet flow lines of the core center and another two are connected to the inlet and outlet flow lines of the core. One side of the core holder has provisions for pneumatic piston pump (for pressure exertion) and water flow. The saline water tank is fitted with the piston pump containing kaolinite clay and the other side of has the flow line for effluent collection. The water tank is fitted with high pressure pump and the flow lines are provided with ball valves and the whole core-oven thermal system is connected to the data acquisition system and subsequently, connected to the computer.

Three sets of experiments were conducted at 100 °C 150 °C, and 200 °C. Initially, the oven was set to these high temperatures. Then the water flow line valves is opened and 2 L of water is pumped to the oven in order to saturate with the limestone core. Typically, limestone rock core has ability of altering the surface reactions with the water such as leaching of salts, adsorption rates, wettability etc, (Gandomkar and Rahimpour, 2015; Austad et al., 2015). Even during this time, there is observation of steam and this is due to the system and rock temperature. After that the kaolinite clay is pumped to the water tank to form a suspension and then suspended water is pumped to the core to saturate with the existing water. Typically, kaolinite clay containing rocks is highly susceptible to fines migration and permeability blockage. For example, Russell et al. (2017), studied the existence of kaolinite effects in rock on fines transport. The authors have conducted laboratory based modeling and analysis of the permeability changes in the rock containing kaolinite during injection of low salinity water. The major observations from their experiments are increase and decrease in permeability as well as the alternation in the water salinity during flow in porous rocks. Also, this has major effects on fines migration and permeability obstruction. Overall, their results highlighted that kaolinite clay content rocks are frequently prone to formation damage and well productivity decline. Next the pressurized air is injected into the core for fines and water mobilization at these temperature regimes. This pneumatic piston is serving as an external pressure source. The mobilized clay fines and water is collected in the effluent collector. This procedure is repeated for another two temperatures and subsequently, a series of curves were obtained, such as water saturation, heat transfer coefficient, enthalpy release, fines concentration, permeability decline, pressure change, and water discharge rate. The experimental outcomes are explored and discussed in the following section.

3. Results and discussions

This section explores the results that were acquired from the coreflood experiments. Fig. 3 presents the variation of water saturation with respect to time.

It can be observed from Fig. 3 that water saturation increases for increasing injection time. All three temperature regimes exhibited an elevation in the water saturation level in limestone core. Notably, higher saturation was noted at 200 °C and it is also inferred that higher reservoir rock temperature enhances the saturation level of the water in a carbonate media. Temperature regime 150 °C exhibited close water saturation value and at 100 °C the differences in the saturation values were higher, but still it displayed a rising curve. For all three temperature regimes between 900s and 1300s the saturation level in limestone core is slightly stabilized and then it climbs rapidly. This may be due to the water wetness and also, other factor may influence in this behavior such as ions exchange, brine, temperature, pressure (Xie et al., 2018; AlHammadi et al., 2018; Sohal et al., 2017). Additionally, higher water saturation is also attributed to the surface energy of the porous hot limestone rock. Incidentally, surface energy determines the water holding capacity of high temperature porous rock formation. Fig. 4 shows the heat transfer coefficient and enthalpy variations with respect to water saturation and time. It can be observed from Fig. 4 a) that the increasing water saturation increases the heat transfer coefficient of the reservoir rock. Earlier it was mentioned that higher temperature elevates the water saturation and subsequent, heat transfer as well. Therefore, there is a heat rejection in the interface between water and rock surface, and subsequently, there is a high degree of heat release. A similar observation was observed for Fig. 4 b), here the enthalpy releases heavily for an increasing injection time. The heat transfer coefficient and enthalpy are the crucial factors in detaching and straining of in-situ fines. As these two parameters reduce the electrostatic force of rock, which is required to hold a fine particle to the surface. As this was widely observed and reported in geothermal reservoirs (You et al., 2019, 2016; 2015). This phenomenon is also possible in conventional and unconventional oil and gas reservoirs, and even in aquifers. Upon fines detachment, an entropy and a new surface energy are produced. Where this provides a space for the effective flow of kaolinite fines suspensions. By applying Onsager principle to this scenario we can learn that fines can create nor destroy entropy in a porous media considering temperature and pressure effects. Differences in T and P with respect to time (t) produces entropy and generally, entropy will be higher during higher reservoir temperatures.

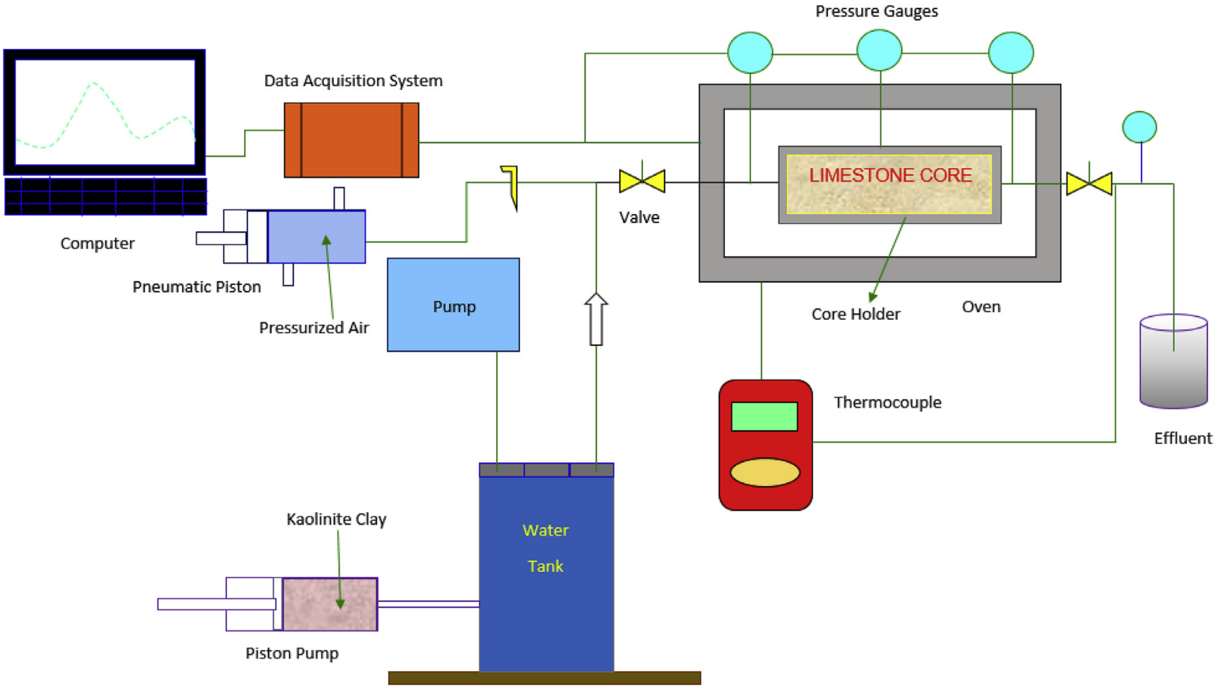

Fig. 2. Schematic diagram of experimental setup.

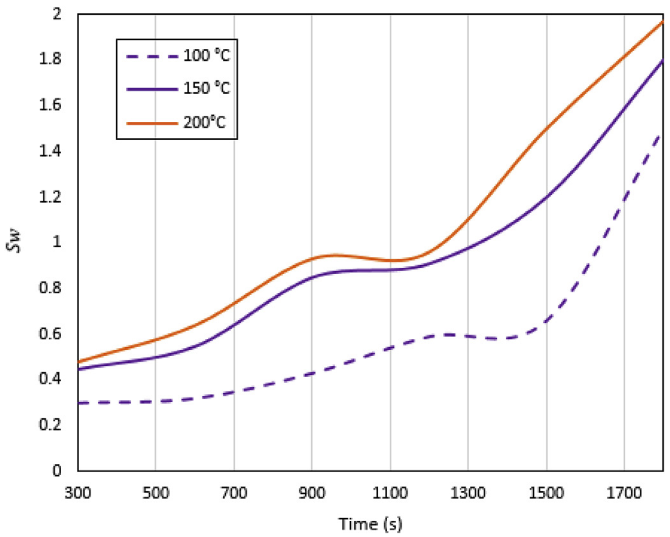

Fig. 3. Water saturation variation for increasing time.

Fig. 5 (a) presents the concentration of kaolinite fines variation with respect to increasing PVI. It can be seen from this figure that at 1 PVI the fines concentration was 8 ppm, 13 ppm, 16.5 ppm for the inflated temperatures 100 °C 150 °C, and 200 °C. At 2 PVI the kaolinite fines concentration increased to 14 ppm, 14.1 ppm, and 17.3 ppm for these temperature levels and finally, climbing to 23.8 ppm, 26.7 ppm, and 38.2 ppm at 8 pore volume injection (PVI). 200 °C contributed in the highest concentration of fines with advancing PVI. Since kaolinite fines possess good thermal potential and entropy. Subsequently, will result in the mass deposits in limestone rocks. Fig. 5 b) shows the permeability decline rate with respect to increasing injection time. This reduction is mainly due to fines lifting, suspension, and straining, rock wettability, temperature and water pH may also contribute in this behavior (Kim and Kovscek, 2013; Marathe et al., 2012; Zeinijahromi et al., 2016). It was reported that higher temperature decreases the permeability of the rock core. As it is evident from the graph that 175 °C displayed heavy decline rate when compared to other temperature regimes. It should be noted that the temperature and injection time drastically reduces the permeability of limestone core. Even the zeta potential at the interface between brine and rock can influence the reservoir fluid transport rate in porous media (Sari et al., 2017). Therefore, saline water-kaolinite fines suspension flow can harshly damage the permeability of the hot carbonate rock formation. Table 1 presents the water suspension data that is water discharge in effluent. Mainly, water discharge decline time and amount of colloidal suspensions under the temperatures 100 °C, 150 °C, and 200 °C were presented (see Fig. 6).

Fig. 6 presents the pressure variation for increasing pore volume injection (PVI). It can be observed from the figure that at all rock temperature regimes such as in 100 °C 150 °C, and 200 °C, the pressure increases steadily for a gradual enhancement in PVI. 200 °C exhibited a higher rise in the rock pressure. Between 4 PVI and 6 PVI the pressure plateaus or stabilized and then it starts to plummet heavily for increasing pore volume injection. Stabilized pressure can be achieved at extreme rock temperatures and a minimum pore volume injection as well. Typically, in these cases, the pressure tends to decline, but surprisingly, it was detected to be higher and this is absolutely due to reservoir rock and fluid temperature. Generally, the pressure across the core varies sharply, especially begins to fall during coreflood experiments (Russell et al., 2018; Chequer et al., 2018; Vaz et al., 2017).

Fig. 7 presents the water discharge rates with respect to times of fines suspension water injection and fresh water injection. It can be seen from Fig. 7 a) that the rate of water discharge from rock core is decreasing rapidly for all three temperature regimes. As suspension water injection time increases the discharge rate also decreases rapidly. During suspension flow the fines will be captured in the pore-throat and consequently, the permeability will be drastically reduced. This causes the decline of the water discharge rate with taking temperature into an account. Fines are easily detached and strained at higher temperatures and subsequently, will lead to formation damage and injectivity decline as well (You et al., 2016). Furthermore, this injectivity decline is also due to fabric texture of the porous rocks, which governs the fluid flow velocity and particle wettability. The suspension flow velocity will be lower during the flow over fabric surface and subsequently, will result in injectivity decline and slow particle capture. It should be seriously

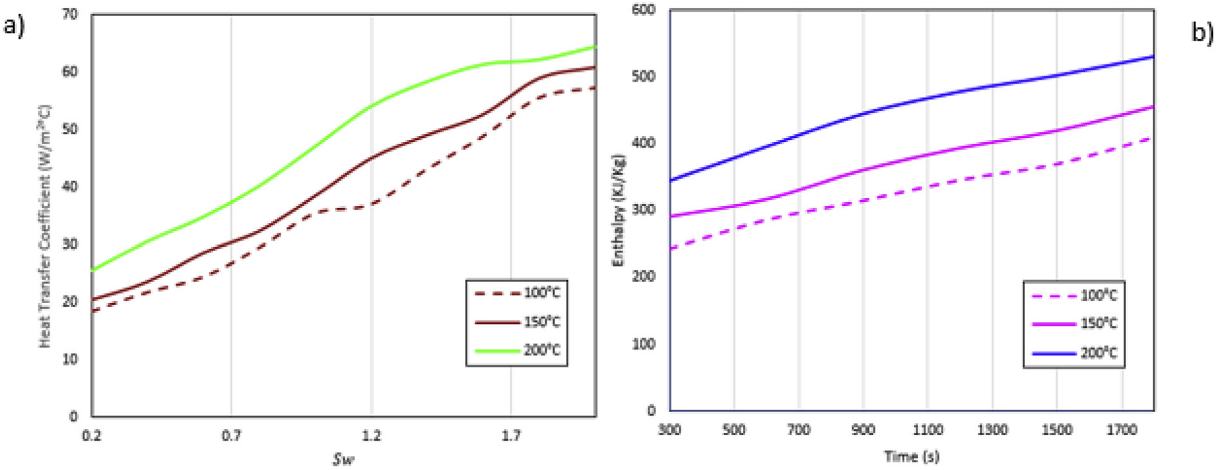

Fig. 4. a) Heat transfer coefficient variation for increasing water saturation, b) Enthalpy variation for increasing time.

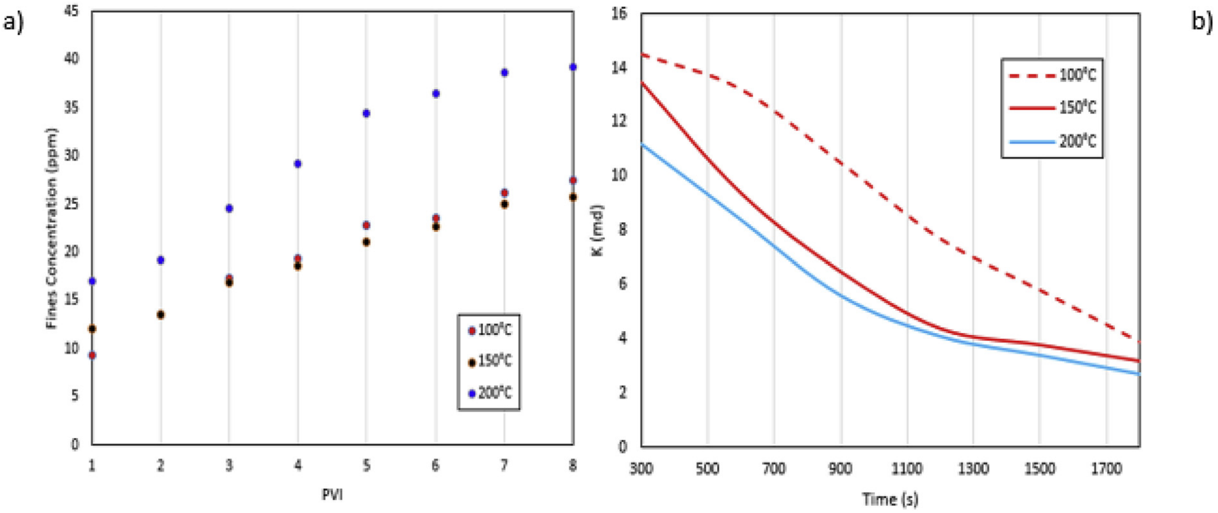

Fig. 5. (a) Fines concentration variation for increasing pore volume injection (PVI) and (b) Permeability decline for increasing time.

Table 1
Suspended water discharge data.

S.No	Temperature (°C)	Water Discharge Decline Time (s)	Amount of Colloidal Suspension (g)
1	100	688	50.26
2	150	1019	72.44
3	200	1327	77.65

taken into a consideration that even a microscale surface roughness will alter the wettability and adsorption capacity of the material surface regardless of temperature effect (Kumar and Prabhu, 2007). On the other side, there is an observation of higher discharge rate for fresh water injection, as shown in Fig. 7 b). Generally, fresh water thermal conductivity is higher than clay intruded water and as a result, the water injectivity and discharge rates are higher (Mideen, 2015) and sometimes, this case may be dominated by the water saturation and rock thermal conductivity heterogeneity (Albert et al., 2017). Heterogeneity has the strongest effect in a carbonate reservoir as this determines the heat extraction and fluid movement towards the well (Pandey and Chaudhuri, 2017).

Fig. 8 shows the change in the electrical conductivity with regards to increasing temperature for both fresh (FW) and saline waters (SW). The electrical conductivity instrument was used in this work. It can be seen from Fig. 8 that the electrical conductivity of fresh water linearly

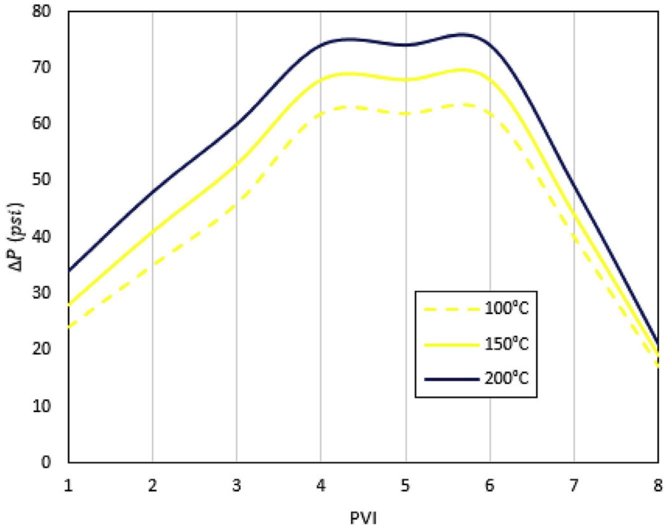

Fig. 6. Pressure variation for increasing pore volume injection (PVI).

soars for enhancing temperatures. Initially, at 100 °C the fresh water (FW) electrical conductivity was noted as 97 µS/cm, 163 µS/cm, and 250 µS/cm for the time 300s, 600s, and 900s. Then, 119 µS/cm, 190 µS/

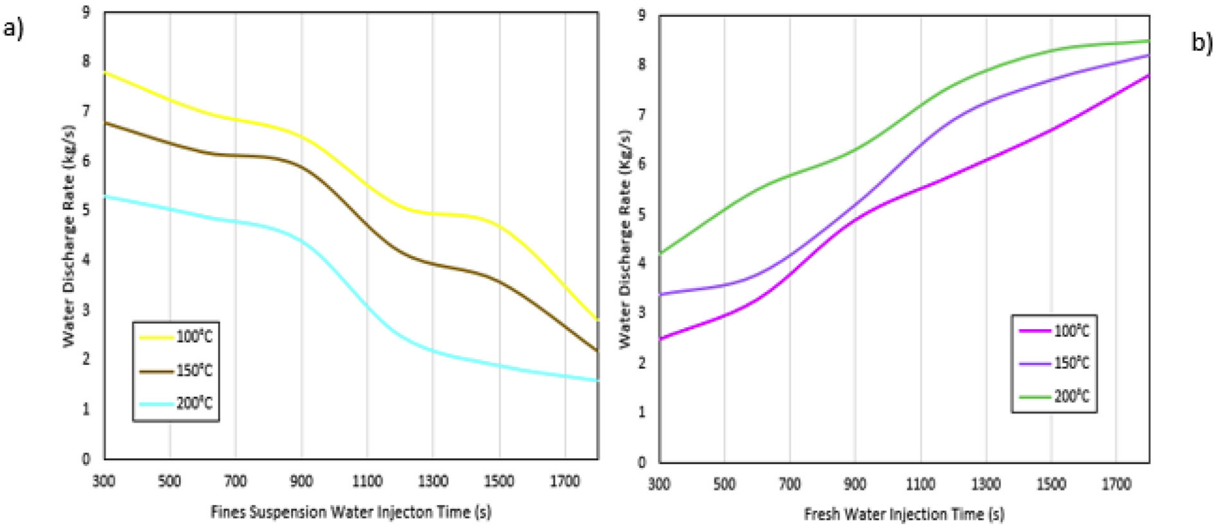

Fig. 7. a) Water discharge decline rate for increasing fines suspension water injection, b) Water discharge decline rate for increasing water injection time.

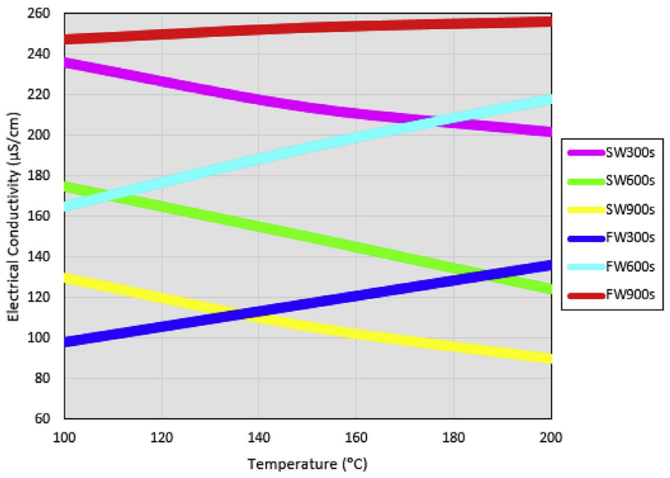

Fig. 8. Variation of electrical conductivity with respect to increasing temperature for both saline (SW) and fresh (FW) waters.

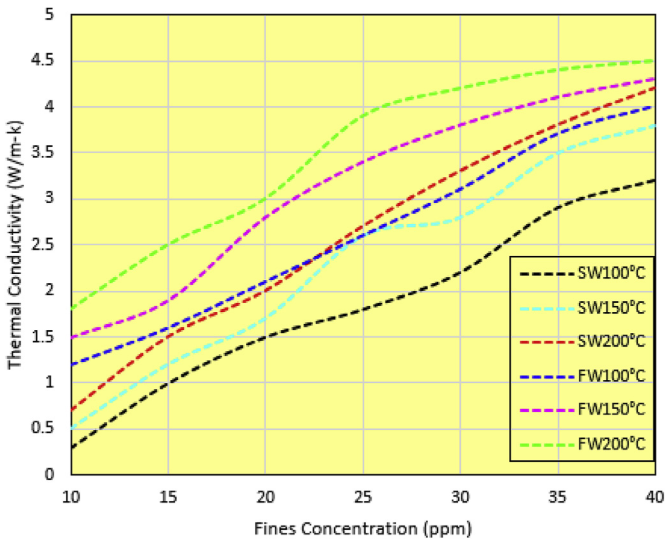

Fig. 9. Variation of thermal conductivity with respect to fines concentration for both saline (SW) and fresh (FW) waters.

cm, 255 µS/cm was observed at 150 °C and highest values of fresh water were recorded at 200 °C, which showed the values of 135 µS/cm, 218 µS/cm, and 257 µS/cm for same time length. But, it should be observed that FW900s exhibited a stabilization curve. The fresh water contains no kaolinite fines concentration and salinity as well. Generally, the electrical conductivity of fresh water will be higher than the saline water (Mideen, 2015). Furthermore, electrical conductivity of saline water with fines presence underwent a gradual deterioration. Actually, this sample is an effluent, which were collected during the experimental work and these results has been compared with the fresh water samples. In this case, the electrical conductivity of saline water (SW) is higher and reduces gradually for advancing temperature. At 100 °C, the electrical conductivity was found to be 125 µS/cm, 176 µS/cm and 238 µS/cm for the time 300s, 600s, and 900s. Additionally, 114 µS/cm, 146 µS/cm and 217 µS/cm was noted at 150 °C at the same time length. A gradual decline was observed in this case and this is due to high presence of kaolinite fines and salinity in water. Finally, reaching to 89 µS/cm, 122 µS/cm, and 201 µS/cm at 200 °C at the same time frame. This effluent water behavior at these physical parameters are mainly due to core temperature, zeta potential, water chemistry, and geochemical alterations (Sharma and Mohanty, 2018; Xie et al., 2017).

Fig. 9 shows the rise of thermal conductivity of fresh (FW) and saline (SW) water for increasing fines concentration. It can be seen from Fig. 9 that the intensity of fresh water thermal conductivity was higher than saline water. Actually, the fresh water with fines concentration possess higher thermal conductivity than that with saline water. The thermal conductivity of fresh water will rise during higher rock temperature and kaolinite are highly excited at higher temperatures. Kaolinite clay has the potential of high thermal energy storage and during suspension in fresh water it enhances the thermal conductivity of the fluid (Li et al., 2015). On other side, kaolinite in saline water enhances the ionic strength and alters the pH (Weber and Stanjek, 2018; Beddiar et al., 2005) and consequently, under high temperature environments the thermal conductivity of saline water will be higher. It can be observed from this figure that the FW and SW showed close variation and increasing temperatures contributes in higher thermal conductivity. Therefore, it can be inferred that both FW and SW will elevates the thermal conductivity of water and subsequently, suspended kaolinite fines will be rapidly transported and strained in porous interspace.

Fig. 10 shows the experimental model validation, which were executed against the statistical based optimization model, RSM (Response Surface Methodology). Where, this RSM analyzes the relationship between multiple explanatory variables and response variables, which is widely used in confirmation experiments and model validations (Nasri and Mozafari, 2018). Design expert software was used to test these

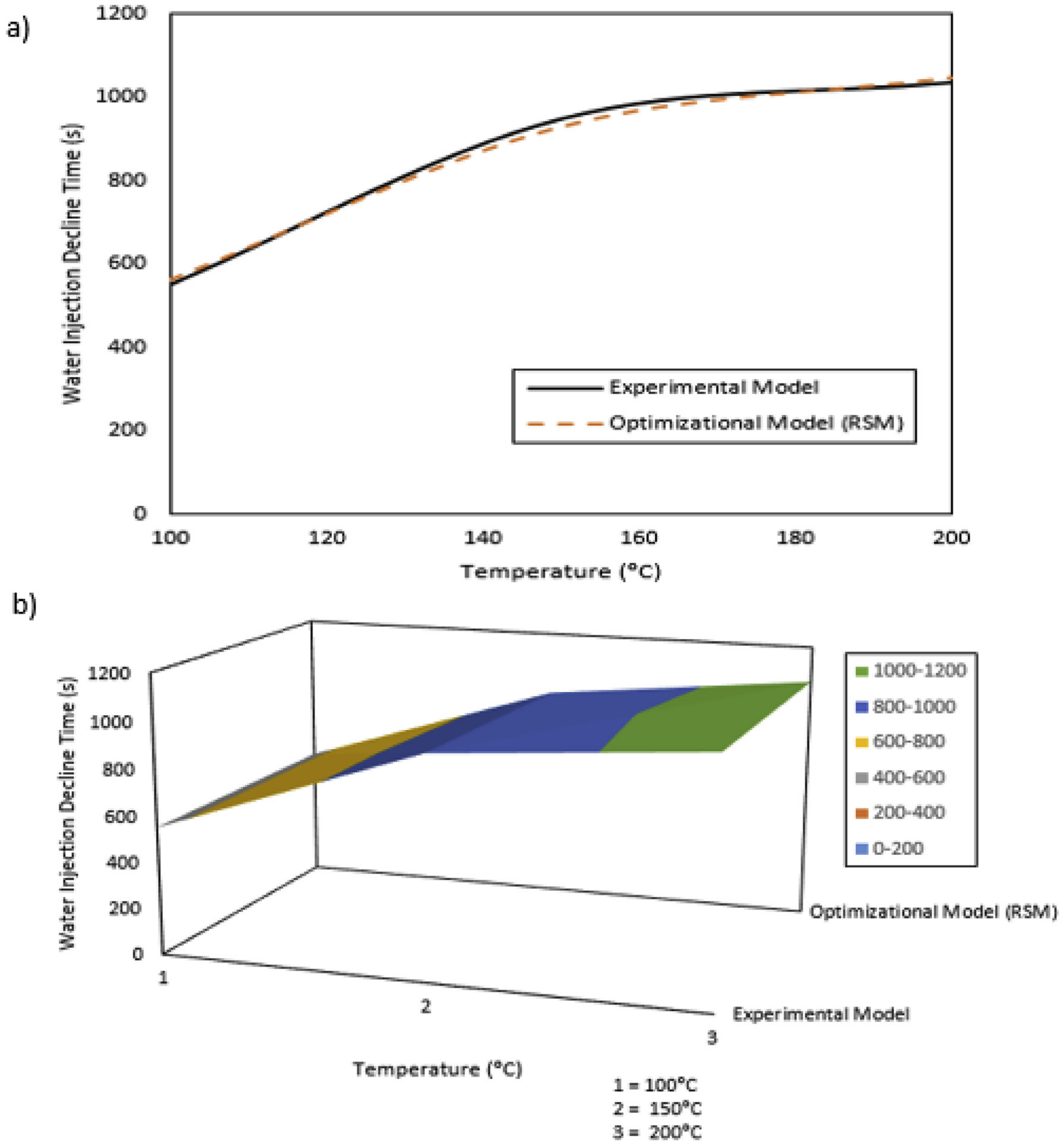

Fig. 10. Model validations: Water injection decline time Vs Temperature, a) XY Scatter Plot, b) 3D Surface Curve.

experimental values against RSM. In this scenario, the performance and correlation of experimental model were evaluated and this can be seen in Fig. 10 a), where the close correlation was made between the statistical-optimization (SO) models with the experimental models or in other words, the overlapping of curves indicates that the response (output) exhibits non-linear variation with respect to the input parameter. This shows that the model is reliable and can be applied for laboratory based coreflood experiments for optimization. Furthermore, it can be seen from Fig. 10 b) surface plots for experimental and RSM model under three different responses (temperature). It indicates the uniform distribution of water injection time rates at these temperature levels and collectively, models exposed good agreement.

4. Conclusions

This work has accomplished the elucidation of in-situ kaolinite clay fines suspension flow in porous limestone (carbonate) media. Based on the mathematical formulation and experimental modeling the following conclusions can be made:

1) A mathematical formulation was successfully applied to the fine particle wettability and heat flow in porous carbonate rocks. In addition, an experimental modeling and analysis was performed to examine the feasibility of fines suspension flow in hot porous limestone rock core. This core was placed in an oven and heated in the temperature 100 °C, 150 °C, and 200 °C. A three sets of suspension flow experiments were performed at these temperature conditions. There is also an observation of steam at temperature conditions.
2) A steady rise in the water saturation in limestone core was observed for enhancing injection time. The higher saturation rate was observed in the temperature of 200 °C and it is implied that when the temperature increases the water saturation rate also elevates rapidly. Furthermore, at these temperature regimes, the water saturation inflates the heat transfer coefficient and in parallel, increasing injection time surges the enthalpy rate.
3) It was observed that increasing PVI enhances the fines concentration. In this scenario also higher temperature (200 °C) contributes in the high degree of concentration of kaolinite fines. This is due to the

fact that the fines are highly excited at higher temperatures. After some time, there is a recording of the permeability decrease of a limestone core due to fine suspension and straining. Huge loss in permeability was recorded in the 200 °C, which plummets steadily. But, on the other side, the pressure over the core increases rapidly for increasing PVI and in 4 PVI the pressure starts to stabilize, and at 5 PVI it starts to plummet. This abnormal pressure behavior is due to the surrounding temperature and internal stress exerted by fines and water saturation.

4) Chiefly, it was observed that the water discharge rate decreases for increasing water injection time of fine suspension. Also, the water discharge rate increases for increasing water injection time. In this case also higher temperature contributes in the rise and fall of the water discharge rate. Then the experimental model was compared with response surface methodology (RSM) an optimizational cum statistical method. On the whole, the modeling upshot indicated good accord.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petrol.2019.01.023.

Nomenclature

K	*Thermal conductivity*
F	*Force*
I	*Lever arm ratio*
T	*Temperature*
A	*Area*
K	*Permeability*
c	*Volumteric concentration of suspended particles*
x	*Distance and $x-$direction*
y	*$y-$direction*
t	*$-$Time*
u	*Velocity*
r	*Radius*
d	*diameter*
h	*height*
g	*gravity*
d	*diameter*
n	*Total number of ordinates*
q	*Fluid flow rate*
v	*Volume*
s	*Solid phase*
f	*Fluid phase*
U	*Darcy velocity*
Φ	*Porosity*
P	*Density*
I and j	*Components*
t_1	*Initial time*
t_2	*Final time*
r_2	*Final time*
r_1	*Initial time*
K_1	*Inital thermal conductivity*
K_2	*Final thermal conductivity*
M_*	*Specific viscosity*
ρ_*	*Relative density*
g_*	*gravity with respect to changing density of the fluid*
k_*	*Change in permeability with respect to flow velocity*
∇_*	*Change in volume of the pore*
V_*	*Darcy term for the fluid momentum balance*
F_i	*Intermolecular force*
$Q_{K\sigma}$	*Slow mobilization of fines with respect to rock surface roughness*
$\dot{t}q$	Fluid flow decline term with respect to time on the basis of fabric theory
r_o	*Change in radius*
K_0	*Varying pore temperature*
Q_d	*Steady state heat development per unit volume per unit time*
T_w	*Well temperature*
T_s	*Surface temperature*
c_P	*Specific pressure*
k_s	*Permeability with respect to surface energy*
∇T_s	*Change in surface temperature*
∇T_f	*Change in fluid phase temperature*
T_f	*Fluid phase temperature*
$\hat{e}g$	Gravity acceleration unit vector
T_{Kh}	Final and highest thermal conductivity of rock surface
T_{Ki}	Initial thermal conductivity of rock surface
$\mathit{\Delta} p$	Change in pressure inside porous media
γ_{sv}	*Rock $-$ vapor surface tension*
γ_{sl}	*Rock $-$ liquid surface interfacial tension*
γ_{lv}	*Liquid $-$ solid contact angle*
μ_i	*Viscosity*
Γ_i	*Charge per unit mass of the ith component*
S_s	*Surface energy entropy*
ν_E	*Rock $-$ liquid interface velocity*
$y_1 + y_2 + y_3$	distance between the ordinates that is the rock teeth
R_∇	*Surface roughness factor*
$\mathit{\Delta} H_i$	*Enthalpy of immersion*
$\eta_{\phi R}$	*Thermal efficiency of porous media with regards to radiation*
$\mathrm{W_R}$	Net work transfer to migrate the reservoir fines in porous media
Q_Ω	Heat transfer to porous media
θ	*Theta (contact angle)*
γ	Continuous heat rejection to porous media from rock surface (without any interval)
β	*Formation damage coefficient*
α	*Heat flux*
ω	*Total work of forming solid surface in vacuum*
σ	*Volumertic concentration of particles in pore chamber*
$\sigma_s + \sigma_a$	*Concentrations of attached and strained fines*

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