Effects of In-situ Clay-induced Formation Damage on Oil Recovery During Low-Salinity-Based Enhanced Oil Recovery Method in a Sandstone Reservoir of Upper Assam Basin, India

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ABSTRACT

Clay-Induced formation damage is a worldwide problem in the petroleum industry, which is caused by the swelling and migration of clays and subsequent plugging of the pore throats. The In-Situ formation damage by clay minerals in sandstone reservoirs is governed by the physicochemical factors that control the stability and transport of the clays. The study presented here focuses on the effects of In-Situ Clay-Induced Formation Damage on oil recovery during Low Salinity Waterflooding (LSW) in the Tipam Reservoir Sandstone of Upper Assam Basin, India. Analysis of reservoir rock, formation brine, and crude oil shows the feasibility of LSW in the study area. The paper describes the alteration of rock permeability and porosity in a series of core flooding experiments using low-salinity brine. It is observed that the permeability and porosity of the flooded core plugs decrease during LSW. The SEM analysis of the fines migrated along with the effluent water during core flooding shows the presence of Kaolinite, Illite, and Mixed-layer. The study shows that the permeability reduction occurs during LSW through the plugging of pore throats which may be due to some mechanical and chemical processes like migration and swelling of clays. This plugging can increase the oil recovery by enhancing the Sweep Efficiency. Also, the migrated clay minerals can enhance the oil recovery by wettability modification and reduction of oil-water Interfacial Tension (IFT). Further, the permeability decline in the Swept Zone may improve the LSW performance by increasing the water breakthrough time and reducing the water cut.

Keywords: Basin, Core Flooding, LSW, Permeability, Wettability

1. Introduction

Formation Damage can be defined as a reduction in the initial permeability of the reservoir rock near the vicinity of the wellbore following various operations such as drilling, completion, stimulation, production, and workover operations (Wilson *et al*. 2014). It includes flow restrictions due to the reduction in permeability in the near-wellbore regions, alteration of the relative permeability to the hydrocarbon phase, and unintended flow restrictions in the completion itself. One of the main reasons behind the productivity reduction in a hydrocarbon reservoir and injectivity problem in a water flood project is the formation damage. Sometimes, the information available makes it very difficult to quantify formation damage that can happen anywhere and anytime (Radwan *et al*. 2019; Civan 2015; Portier *et al*. 2007; Bennion *et al*. 1995). Therefore, it is better to avoid formation damage than to restore it because restoring formation damage may result in additional damage to the formation (Al-Hetari 2017).

Formation damage can be caused by different Mechanical, Chemical, Thermal, and Biological methods (Al-Hetari 2017; Ezenweichu & Laditan 2015). The Mechanical formation damage results from the migration of clays (fines migration) like Kaolinite and Illite and the subsequent blocking of some of the pore throats in the reservoir rock (Mohan *et al*. 1993). The three basic steps of formation damage by fines migration are the presence of fines in the rock, migration of fines, and trapping of the fines in place (Xiao *et al*. 2017). This fines migration in a petroleum reservoir depends on different factors like mineralogical composition, porosity & permeability of the rock, injection & formation brine salinity, brine pH, temperature, Residual Oil Saturation (ROS), the fractional flow of oil & water, rock wettability, oil polarity and drag force (He *et al*. 2012; He *et al*. 2013; Hibbeler *et al*. 2003; Huang *et al*. 2008; Kalfayan & Watkins 1990). The mineralogical composition of a reservoir rock plays a major role in fines migration as the clay minerals in the rock migrate along with the flowing fluid under favorable conditions. It is observed that low salinity and high pH of brine cause fines to be released from the pore walls (Vaidya & Fogler 1990; Tang & Morrow 1999). It is also found that the permeability of a rock sample decreases with increasing temperature due to fine migration (Rosenbrand *et al*. 2015). Apart from the fines migration, blocking of pore throats by external solids, perforation damage, and phase trapping are some other mechanical methods of formation damage.

The Chemical Methods of formation damage include mainly swelling of clays and precipitation of insoluble solids (Al-Hetari 2017). Swelling of clay occurs when the initial equilibrium state of the Crude Oil/Brine/Rock (COBR) system is disturbed, especially during the injection of low-salinity brine into a reservoir containing clay. Clay swelling also occurs during drilling, completion, stimulation, and work over operation. Clay minerals are built from layers (sheets) of SiO_4 tetrahedrons and octahedrons like $Al_2(OH)_6$)n or ((Fe or $Mg)_3(OH)_6$)n. These tetrahedral and octahedral layers are stacked on top of each other.The swelling of the clays is due to the increase in interlayer spacing in clay particles (Zhou *et al*. 1996). These clay minerals have Cation Exchange Capacity (CEC), which is a measure of their ability to attract and hold cations from the bulkfluid (Hamilton 2009). Earlier studies have found that Kaolinite, Illite, and Smectite clays have high CEC that can cause a local pH increase in the vicinity of the clay surfaces (Austad *et al*. 2010; Hughes *et al*. 2010). This pH increase in the surrounding solution increases the detachment of fines from the pore walls, as mentioned above. On the other hand, the precipitation of insoluble solids in the porespaces is caused due to chemical reactions or disturbances in thermodynamic equilibrium. When the chemistry of the injection brine and reservoir fluid is different, there is always a possibility of formation damage through clay swelling and insoluble solid precipitation. These precipitants can be either from the brine (inorganic compounds) or from the crude oil (organic species), where the precipitation occurs due to the alteration of temperature or pressure near the vicinity of the wellbore or from the changes inthe injected fluid composition (Economides *et al*. 1994).

Formation damage by Thermal Methods occurs during some high-temperature Enhanced Oil Recovery (EOR) operations like In-situ Combustion and Steam Injection. These high-temperature operations may lead to mineral dissolution and transformation, where rock minerals are catalyzed and transformed from the earlier nonreactive clays to reactive products, which result in clay swelling, clay deflocculation, and reduction of rock permeability (Faergestad 2016). On the other hand, Biological Formation Damage is the result of the chemical interaction between the bacteria and food substances present in sandstone reservoirs. It is widely acknowledged that bacteria are present in sandstone reservoirs (Scott & Davies 1993). The introduction of bacteria into the formation can also occur during drilling, water flooding, Microbial Enhanced Oil Recovery (MEOR), and some other operations. These bacteria can result in partial plugging of the pore by bacterial slimes and precipitation of insoluble precipitants (Shibulal *et al*. 2014).

It has been recognized that clay minerals can cause significant damage to the formation of a hydrocarbon reservoir which can reduce the permeability of a reservoir by more than 90% (Zhou *et al*. 1995). Earlier studies have found that Low Salinity Water flooding (LSW), which is a new Enhanced Oil Recovery method, causes In-Situ formation damage (Tang and Morrow 1999). In LSW, injection water salinity is comparatively lower than the reservoir brine salinity, which causes the Smectite and Mixed-layer to swell along with the breakage of fines that are in contact. These fines are then migrated (Swelling Induced Migration) along with the clay minerals, which are directly migrated (mainly Kaolinite and Illite) by the 'Fine Migration' mechanism. These migrated, and swelling clays can block some of the pore throats in the reservoir rock resulting in a reduction of permeability. Thus, LSW can cause In-Situ Clay-Induced formation damage in the swept area through Clay Swelling, Clay Migration, and Swelling Induced Migration (Tang & Morrow 1999; Mohan *et al*. 1993). Therefore, proper design of the Low-Salinity-Based EOR method is very important to reduce the formation damage, which includes fines management (Civan 2007, 2010; Fogden 2012). However, although the Clay-Induced formation damage from Low-Salinity-Based EOR reduces the connectivity in the formation, it can also enhance the oil production through the improvement of Sweep Efficiency, increasing the water breakthrough time and reducing the water-cut (RezaeiDoust 2009; Zeinijahromi *et al*. 2011). In addition to this, the migrated clay minerals can reduce the Residual Oil Saturation through the wettability alteration of rock and reduction of oil-brine Interfacial Tension (Tang & Morrow 1999; Bruin 2012). In this paper, a study has been made on the effects of In-Situ Clay-Induced formation damage on oil recovery during LSW in the Tipam Reservoir Sandstone of Upper Assam Basin.

2. Materials and Methods

For the present study, the Reservoir Rock sample, Crude Oil sample, and some Formation Brine data were collected from the study area. The Reservoir Rock samples were collected from five different wells from the area under study, whereas the Crude Oil sample was collected directly from a producing well located in the study area. All the rock samples were from the Tipam Reservoir Sandstone of the Upper Assam Basin. The depth range of the rock samples are 2893.00 m-2902.00 m, 2962.00 m-2970.00 m, 2898.43 m-2906.00 m, 2964.00 m- 2973.00 m, and 2853.00 m -2861.00 m.

2.1 Analysis of Reservoir Fluids

Crude Oil analysis was done to determine asphaltene content, resin content, Water Cut, density, Pour Point, wax content, and Acid Number as per the IP143, IOC-AOD, IP358, IP160, IP015, UOP 46-85, and IP001 standards, respectively. The analysis shows that Crude Oil contains resin and asphaltene with an Acid Number of 0.58 (Medhi 2018). Earlier studies show that the polar compounds (resin and asphaltene) and high Acid Number (>0.2) of oil are suitable for the application of LSW in an oil reservoir (Lager *et al*. 2008a; Ehrlich *et al*. 1974; Ehrlich & Wygal 1977).

The Formation Brine analysis shows that its salinity is 1404 ppm (as NaCl) which contains Ca^{2+} (6 ppm) and Mg^{2+} (8 ppm) (Medhi & Das 2015). According to Lager *et al*. (2008a) and Lager *et al*. (2006-8), the presence of Ca^{2+} and Mg^{2+} in the formation brine is the mandatory ions required for obtaining the LowSal Effect (LSE).

2.2 Petrographic Analysis

Petrographic analysis of rock helps to determine the mineralogy and texture of the rock types. The study also provides information about the diagenetic history, cementation, degree of compaction, effect of pressure solution, and subsidence of the basin of deposition (Das 1996). In the present work, mainly the mineralogy of the reservoir rocks is studied along with the texture of the rocks to some extent to evaluate their role in formation damage and oil recovery during LSW. In this study, the minerals in the rock samples were identified with the help of Thin Section Analysis (Fig. 1), X-Ray Diffraction (XRD) Analysis (Fig. 2 & 3), and Scanning Electron Microscopic (SEM) study (Fig. 4).

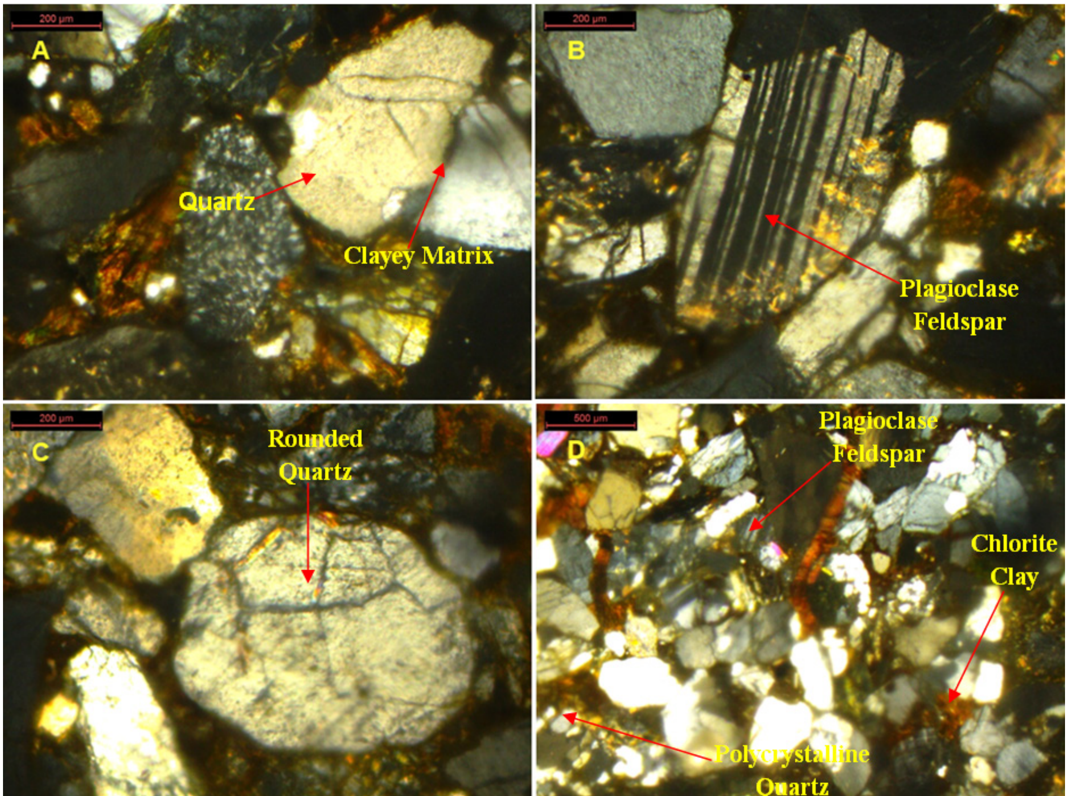

Fig. 1: Photomicrographs of the rock samples of the study area showing Quartz, Clayey Matrix (A); Plagioclase Feldspar (B); Rounded Quartz (C); Plagioclase Feldspar, Polycrystalline Quartz, Chlorite Clay (D).

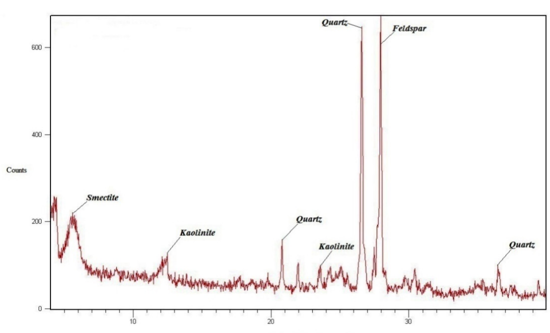

Fig. 2: X-Ray Diffractogram of the 'Rock Sample A' showing Kaolinite, Smectite, Feldspar, and Quartz (Medhi 2016)

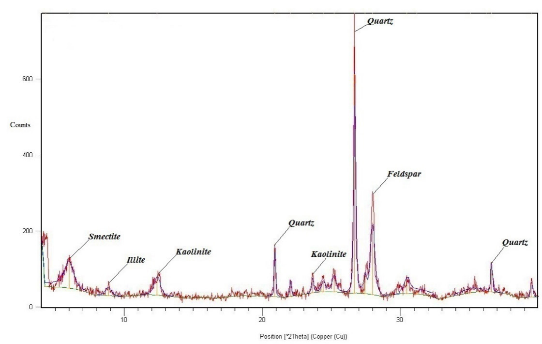

Fig. 3: X-Ray Diffractogram of the 'Rock Sample B'showing Kaolinite, Illite, Smectite, Feldspar, and Quartz (Medhi 2016)

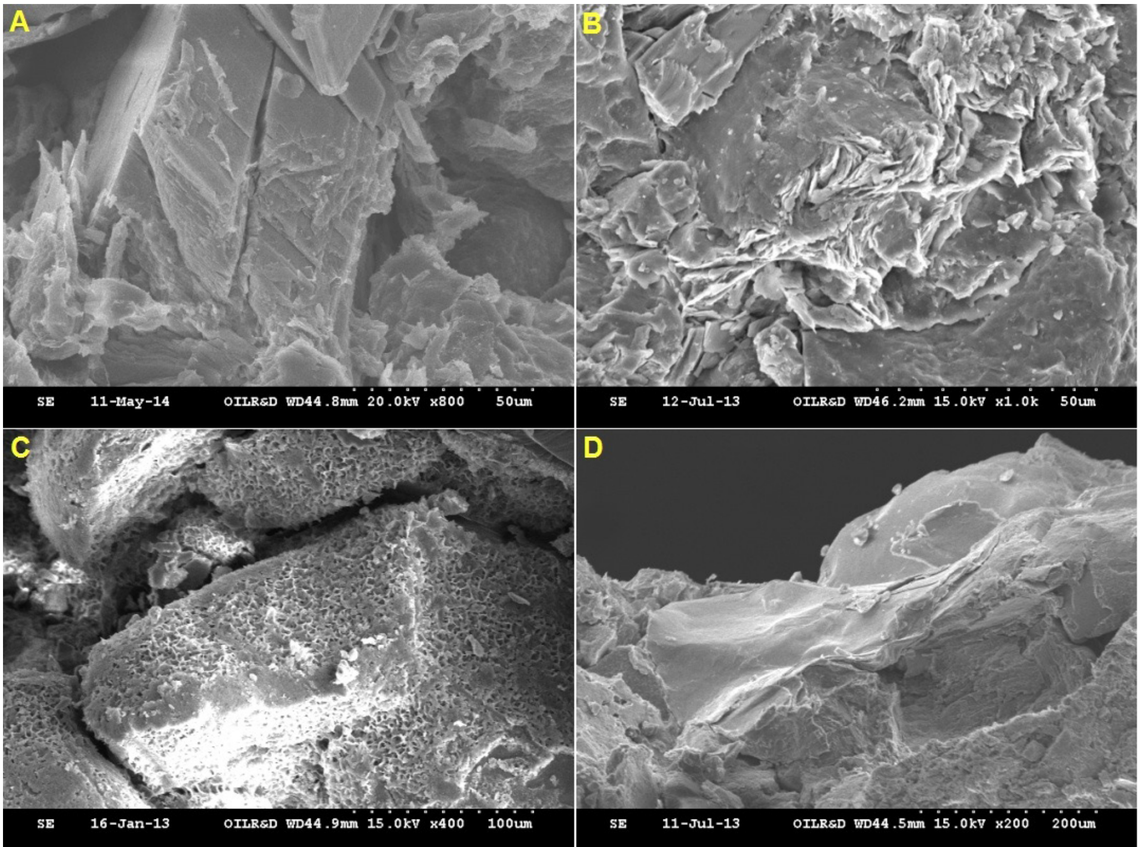

Fig. 4: SEM Photomicrograph of the rock samples of the study area showing Feldspar (A), Illite (B), Smectite (C), and Mica (D).

2.3 Preparation of Core Plugs

For this study, eight Sandstone Core Plugs (1.5-inch dia.) were plugged from the Conventional Core Sample using the Core Plugging Machine, which are then end-faced. The Core Plugs were then cleaned using Soxhlet Apparatus (Fig. 5) and Ultrasonic Cleaner. The cleaned Core Plugs were dried properly in the Humidity Cabinet to remove the liquid present inside the plugs. As the reservoir rock contains a high amount of clay (as per API RP 40. 1998), as observed in the petrographic analysis, the drying process was done at a Dry Bulb Temperature of 63 ^{0}C and Relative Humidity of 40% (Table 1). The clean and dry Core Plugs were then preserved properly for further laboratory experiments. Some of the prepared Core Plugs are shown in Fig. 6

Fig. 5: Core Plugs Cleaning by Soxhlet Apparatus

Table 1: Core Plug Drying Methods and Required Temperature (API RP 40. 1998)

Sl. No.	Rock Type	Method	Temperature (0C)
1	Sandstone (Low clay content)	i) Conventional Oven ii) Vacuum Oven	116 90
2	Sandstone (High clay content)	Humidity oven, 40% relative humidity	63
3	Carbonate	i) Conventional oven ii) Vacuum oven	116 90
4	Gypsum-bearing	Humidity oven, 40% relative humidity	60
5	Shale or other high clay rock	Humidity oven, 40% relative humidity Conventional vacuum	60

Fig. 6: Clean and Dry Core Plugs

Fig. 7: Determining Air Permeability of Core Plug by NDP-605 NanoDarcy Permeameter

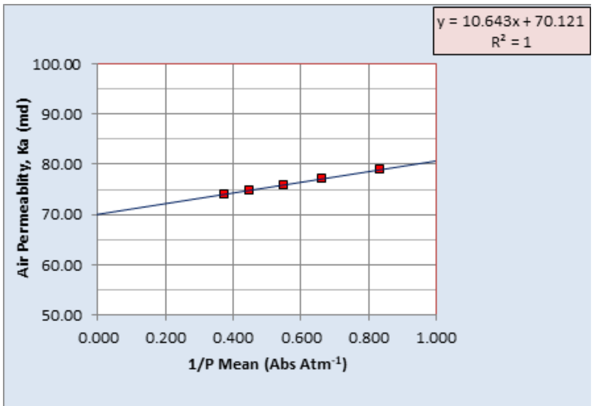

Fig. 8: Air Permeability vs. Inverse of Mean Pressure.

Table 2: The Porosity and Permeability of the Core Plugs

Core plugs	Effective Porosity (%)	Air Permeability (md)	Theoretical Liquid Permeabilty(md)
1	12.56	49.27	41.93
2	20.93	134.87	120.40
3	16.59	80.76	70.12
4	17.88	39.75	31.81
5	18.83	70.75	63.45
6	19.99	65.60	54.19
7	17.68	42.75	33.60
8	16.24	68.41	57.84

2.4 Determination of Porosity and Permeability

After measuring the Effective Porosity of the clean and dry Core Plugs using Coretest TPI-219 Instructional Helium Porosimeter, the Air Permeabilities of the Core Plugs were determined using NDP-605 NanoDarcy Permeameter (Fig. 7), and corresponding Theoretical Liquid Permeabilities were determined based on Klinkenberg Effect. The plot of Air Permeability (md) and Inverse of Mean Pressure (1/Pm) for the Core Plug-3 are shown in Fig. 8. The porosity and the permeability of the eight Core Plugs are given in Table 2.

2.5 Low Salinity Brine Flooding

The core flooding of the above core plugs was done using Ruska Positive Displacement Pump (Fig. 9) at an injection rate of 112 cc/hour using different low-salinity brine. The salinity of the injection brines was reduced up to 14% from the reservoir brine salinity (1404 ppm). Here, the volume displaced by the movement of the plunger of the pump is expressed on a linear scale calibrated in a cubic centimeter (cc), where the flow rate of the injected liquid is adjusted by adjusting its different levers. In this experiment, more than 15 Pore Volume (PV) oil and brine were flooded in each of the core plugs. During the flooding, produced brine and oil were collected and measured carefully for further study (Fig. 10).

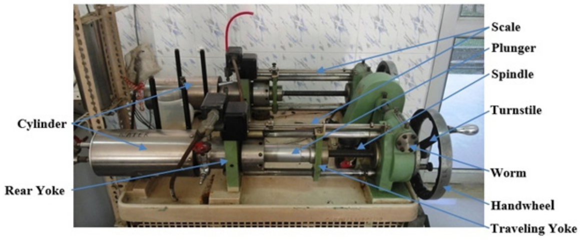

Fig. 9: Ruska Positive Displacement Pump

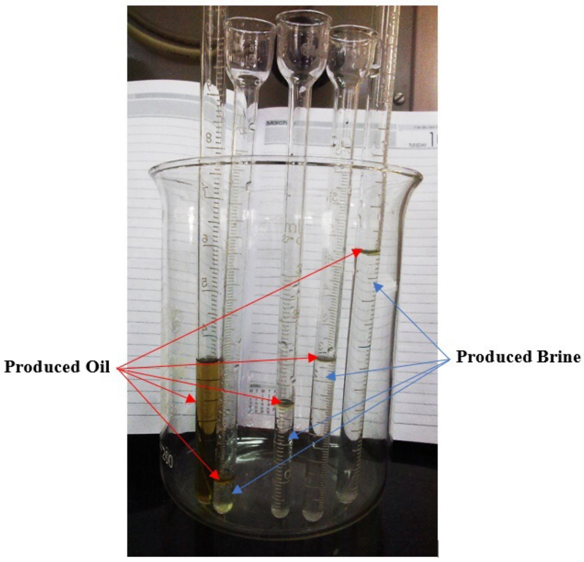

Fig. 10: Produced Brine and Oil during Core Flooding

2.6 Study of Migrated Fines

During the core flooding, some fines were observed in the produced effluent brine, which was migrated along with the flowing brine. In this study, the migrated fines were separated from the produced brine using filter paper. The filter paper containing the fines was dried for a sufficient time. The dry fine sediments were then collected and analyzed under Scanning Electron Microscope (SEM). Fig. 11-12 shows the SEM Photomicrograph of the migrated fine sediments.

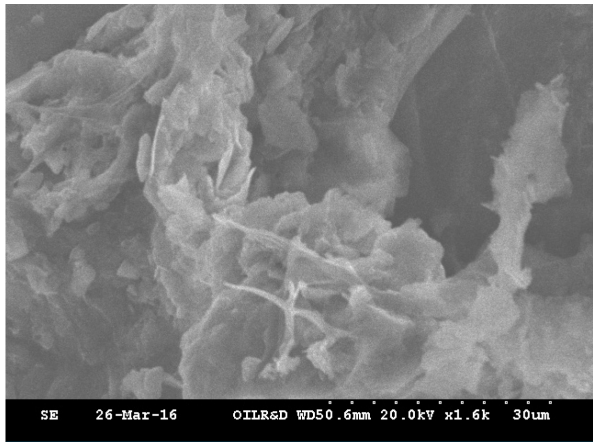

Fig. 11: SEM Photomicrograph of Migrated Fines showing Illite

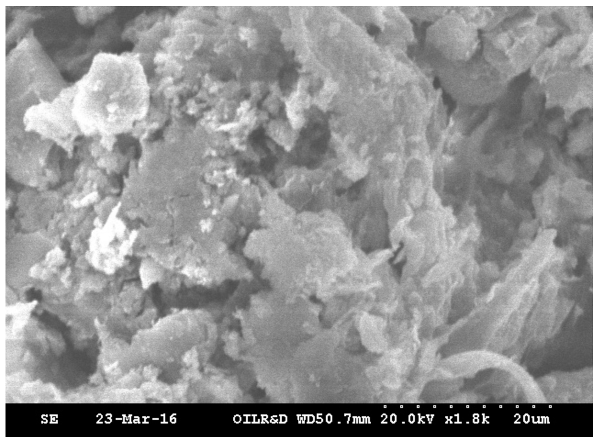

Fig. 12: SEM Photomicrograph of Migrated Fines showing Mixed-layer

2.7 Determination of Porosity and Permeability of the Flooded Core Plugs

For determining the alteration of porosity and permeability during LSW, all the flooded core plugs were cleaned and dried properly using the methods mentioned above. The porosity and the permeability of the core plugs were then determined again using the same porosimeter and permeameter. The porosity and the permeability of the core plugs after flooding are given in Table 3.

Table 3: The Porosity and Permeability of the Flooded Core Plugs

Core plugs	Effective Porosity (%)	Air Permeability (md)	Theoretical Liquid Permeability(md)
1	11.46	47.50	38.46
2	19.54	128.00	112.10
3	16.31	80.75	67.96
4	17.14	37.68	30.11
5	18.59	70.13	63.28
6	17.90	62.46	53.78
7	16.39	38.15	32.35
8	15.12	66.39	55.42

3. Results and Discussion

The rate of In-Situ Clay-Induced formation damage depends on the Physico-chemical factors that control the clays and the properties of the rock matrix surface. Mainly, the clay and mineralogy of the rock matrix, injection fluid chemistry, micromorphology of the reservoir, and crude oil composition govern the extent of the damage in the formation. Therefore, an analysis of the three main elements of the COBR system (Crude Oil, Brine, and Rock) has been done before the study of formation damage and its effects on oil recovery during LSW in the Tipam Reservoir Sandstone of Upper Assam Basin in the depth range 2853.00 m-2973.00 m.

The petrographic analysis (SEM, XRD, and Thin Section) shows that Smectite, Illite, and Kaolinite clays are present in the reservoir rock of the study area along with Mica and Plagioclase Feldspar (Fig. 1-4). As mentioned above, migration of those clays occurs during the injection of low-salinity brine into the formation. In addition to the direct migration of Kaolinite and Illite, Swelling-Induced Migration of clays & Mica and swelling of the Smectite occur during the LSW. This In-Situ migration and swelling of clays can reduce the rock permeability by blocking some of the pore throats. However, the migrated and swelling clays can improve the oil recovery by alteration of rock wettability, reduction of oil-brine IFT, and Improving Sweep Efficiency, as mentioned earlier. Also, the permeability decline may improve the water flood performance by increasing the time of water breakthrough and reducing the water cut (Zeinijahromi *et al*. 2011). The presence of the Plagioclase Feldspar in the rock indicates that the Tipam Reservoir Sandstone is a good candidate for LSW (Hughes *et al*. 2012).

Earlier studies have shown that the substitution of different ions takes place in the lamellae of the clays, which can cause unbalanced internal negative charges in the lamellae (Bathija 2009). These unbalanced negative charges are compensated by the adsorption of oppositely charged ions on the external surfaces of the clays from the surrounding brine (Worden and Morad 2003). It is found that clay minerals can exchange the cations adsorbed on their external surfaces and between the layers of the clay structure, which is called Cation Exchange Capacity (Hamilton 2009). As mentioned earlier, Smectite, Illite, and Kaolinite have high CEC, which can increase the pH of the brine close to their surfaces (Austad *et al*. 2010; Hughes *et al*. 2010). As a result, more clays can be released from the pores' inner wall and then migrate along with the injected low-salinity brine. These migrated clays can block some of the pore throats in the rock resulting in permeability reduction. It is also found that the high pH of the brine phase results in the improvement of water-wetness of the reservoir rock through the desorption of organic materials from the clay surfaces that improve the oil recovery (McGuire *et al*. 2005; RezaeiDoust *et al*. 2010). Additionally, the reaction of acid compounds of crude oil occurs in the high pH environment that generates some surfactant In-Situ (Boussour 2009). These surfactants can reduce the Interfacial Tension (IFT) between the reservoir oil & brine, which further reduces the Residual Oil Saturation in the reservoir. If the pH of the brine increases to above 9 in a petroleum reservoir, the flooding process would be equivalent to an Alkaline Flood (McGuire *et al*. 2005).

The analysis of the formation fluids shows that polar compounds (resin and asphaltene) and divalent cations (Ca^{2+} and Mg^{2+}) are present in the crude oil and formation brine, respectively. It is observed that polar compound adsorption occurs on the clay surfaces when there is direct contact between the oil phase and the rock containing clays. The factors that affect this adsorption on clay surfaces include pH, type of clays, and their exchangeable cations (Clementz 1976; Czarnecka & Gillott 1980; Austad *et al*. 2010). The adsorption of the polar compounds of oil on the clay surfaces occurs mainly by Ligand Bridging and Cation Exchange (Lager *et al*. 2008b). In Ligand Bridging, polar compounds adsorb on the clay surface by multivalent cations (Ca^{2+} and Mg^{2+}), whereas Cation Exchange involves the direct adsorption of polar compounds on the clay surface by displacing the cations. During LSW, when the clay migration occurs, oil droplets attached to the clay surfaces also move along with the injection fluid, which improves the oil recovery. Also, the high Acid Number of crude oil (0.58) can shift the rock wettability to more water-wet condition through the In-Situ generation of some surfactants during LSW as observed in the earlier studies (Ehrlich *et al*. 1974; Ehrlich & Wygal 1977). This wettability modification can further contribute to the additional recovery of oil.

Analysis of the migrated fines shows that Illite and Mixed-layer are migrated along with the injected low salinity brine during core flooding. Earlier studies also observed Kaolinite migration in the study area during LSW in a core flooding experiment (Medhi 2018). This indicates that Kaolinite, Illite, and Mixed-layer migration occurs in the area under study during LSW, which can improve the recovery of oil along with a reduction of permeability of the core plugs.

The routine core analysis of the prepared core plugs shows that the Porosity and the Air Permeability are in the range of 12.56% - 20.93% and 39.75 md-134.87 md respectively (Table 2). From the Klinkenberg Effect study, the Theoretical Liquid Permeability is found to vary between 31.81 md and 120.40 md. The low salinity core flooding experiment shows that an additional 06.20% of Original Oil In Place (OOIP) oil recovery is possible above the core flooding using reservoir brine. After the core flooding, the Porosity and the Air Permeability of the flooded core plugs are in the range of 11.46%-19.54% and 37.68 md-128 md respectively (Table 3). The Theoretical Liquid Permeability varies between 30.11 md and 112.10 md. It is seen that both the Porosity and the Permeability of the core plugs are reduced after the LSW, which is due to the migration of Illite & Mixed-layer, and swelling of Smectite.

The main finding of the results of this study is the In-Situ Clay-Induced Formation Damage that occurs in Tipam Reservoir Sandstone of Upper Assam Basin during Low Salinity Waterflooding. Reduction of the Theoretical Liquid Permeability from 31.81 md - 120.40 md to 30.11 md - 112.10 md occurs due to the plugging of pore throats by some mechanical and chemical processes like migration of Kaolinite, Illite & Mixed-layer and swelling of Smectite clays. This plugging can increase the oil recovery by improving the Sweep Efficiency. The formation damage caused by Fine Migration and Clay Swelling can improve Sweep Efficiency during LSW by altering rock wettability towards more water-wet conditions, reducing oil-brine interfacial tension, and blocking some of the pore throats of the reservoir rock. The wettability modification and IFT reduction promote the movement of injection water more efficiently in the reservoir thereby improving the Sweep Efficiency. Additionally, the reduction in permeability due to the blockage of pore throats can redirect the injected water toward the previously un-swept regions, ensuring better coverage of the reservoir and improved oil recovery. Moreover, the permeability decline in the Swept Zone can improve the LSW performance by increasing the Time of Breakthrough of the injected low salinity brine and reducing the water cut.

These findings significantly enhance the existing knowledge by comprehensively elucidating the complex mechanisms underlying Clay-Induced Formation Damage and its impacts on oil recovery during LSW. By integrating petrographic analysis of rock, reservoir fluid characterization, and core flooding experiments, the study reveals the complex interactions among clays, brine, and crude oil. Additionally, the study demonstrates the potential of LSW to formation damage while enhancing oil recovery, offering valuable insights for optimizing reservoir management strategies in sandstone reservoirs, particularly in the context of the Tipam Reservoir Sandstone of Upper Assam Basin.

However, the challenges encountered in this study include accurately characterizing the complex physico-chemical interactions among clays, crude oil, injection brine, and formation brine. Additionally, quantifying the extent of damage and its impact on reservoir characteristics requires sophisticated analytical techniques. Moreover, replicating reservoir conditions in laboratory experiments poses logistical and technical challenges. Addressing these limitations is crucial for advancing understanding and optimizing recovery strategies during LSW in Sandstone Reservoirs.

4. Conclusion

The In-Situ Clay-Induced Formation Damage occurs in the area under study during Low Salinity Water flooding by the migration and swelling of Kaolinite, Illite, Smectite, and Mixed-layer. However, this formation damage can improve the oil recovery efficiency by Improving the Sweep Efficiency, increasing the water breakthrough time, and reducing the water cut. The migrated clays can also increase the recovery of oil through wettability modification and oil-brine IFT reduction in the Tipam Reservoir Sandstone (depth range 2853.00 m-2973.00 m) of Upper Assam Basin.

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