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Examining Thermal and Salinity Impact on Flow of Crude Oil through Porous Media for Enhancing Recovery

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ABSTRACT

The objective of this study is to examine the influence of reservoir temperature and injected formation brine salinity on oil recovery enhancement in brown oil fields. The study employed core flooding experiments using actual crude oil-producing porous media represented by core plugs, with recovery efficiency used as the main evaluation parameter. Flooding tests were conducted at 65°C, 75°C, 85°C, 95°C, and 105°C, representing reservoir temperatures of selected oil wells in the Upper Assam Basin. Initial water flooding was performed using low-salinity injection water of 897 ppm, followed by subsequent flooding using higher-salinity brine of 8000 ppm under the same temperature conditions. SARA analysis was also conducted to characterize the crude oil composition in terms of saturates, aromatics, resins, and asphaltenes. The results show that low-salinity flooding at 897 ppm produced oil recovery efficiencies of 51.47%, 44.21%, 89.89%, 36.33%, and 16.22% at 65°C, 75°C, 85°C, 95°C, and 105°C, respectively. When salinity was increased to 8000 ppm, the corresponding recovery efficiencies were 22.22%, 38.73%, 59.48%, 43.33%, and 4.98%. The highest oil recovery was achieved at 85°C for both salinity levels, with 89.89% recovery at 897 ppm and 59.48% at 8000 ppm. These findings indicate that reservoir temperature strongly affects crude oil recovery, while injection brine salinity also plays an important role. The study concludes that thermal and salinity-induced wettability alteration occurs during low-salinity water flooding, contributing to improved oil recovery in brown oilfields.

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1. INTRODUCTION

This study undertakes an experimental design to examine how the oil production from brown oil reservoirs could be enhanced post completion of the primary production phase. Many past studies propose that chemical EOR employing Alkaline-Surfactant-Polymer (ASP) flooding may improve oil recovery. Some studies find that secondary recovery yields varying recovery efficiencies depending on reservoir behavior. This study bridges the research gap by examining the effect of reservoir temperature and salinity of injected brine while performing secondary recovery in reservoir rock for enhancing crude oil recovery from brown oil wells suffering from diminished crude oil production. Previous studies lacked in addressing this research gap and did not consider effects of reservoir temperature and salinity together in examining wettability alteration possibility with low salinity water flooding. The objective of this study is to find out whether wettability alteration is possible with this approach or not which is very dominant in the conventional EOR with ASP flooding.

The reservoir fluid interactions (oil and water) during the production of crude oil from an oil well under secondary recovery are characterized by the interfacial tension, while the rock-fluid interaction has a contact angle [1]. Capillaries in any porous media tend to hold the crude oil unproduced. Chemical EOR is an effective solution to dislodging the trapped crude oil [2]. The chemical precipitation issues faced with chemical injection, however, lower the oil recovery efficiency. Low salinity water flooding (LSWF) plays a superior role in this aspect, as it is free from any deposition issues. Considering these advantages, a third method, i.e., hybrid EOR, combines the benefit of LSWF and chemical EOR. In hybrid mode, three different chemicals, surfactant, polymer, and alkaline are mixed together to LSWF. This technique is competitive with the chemical EOR and has varying advantages and recovery efficacy [3-6]. To this, the addition of nanoparticles (hybrid EOR) affects the stability and interfacial tension between the liquid-liquid interactions in addition to changing the wettability [7, 8].

The effect of chemical EOR on carbonate reservoirs is not always viable. In carbonate reservoirs, LWSF often yields a higher oil recovery than chemical EOR. Whatever recovery is obtained from carbonate reservoirs is driven by a change in wettability [9]. In addition to the reservoir issue, it is necessary to ensure that secondary recovery wells are initially produced using certain artificial lift processes. Therefore, a thorough examination of the well's non-flowing reason during the initial production phase is necessary [10]. High viscous oil production with LSWF is influenced by reservoir temperature. As the temperature increases, the relative permeability of crude oil improves, while the relative permeability of water decreases. In addition, irreducible water saturation increases, thereby causing a higher water-wetting condition [11].

The process of displacing oil with water (either surfactant or low salinity water) remains unaffected by reservoir pressure. Some microfluidic studies observe that the displacement process is accelerated with the addition of surfactant to LSWF and is not influenced by pressure. Surfactant rich flooding may lead to increased oil recovery at increased temperature [12-15]. Knowing of initial rock wettability helps in identifying the appropriate oil recovery method. Rocks initial wettability is caused by the fluids that first occupy the porous media. In addition, the surface behavior of the rock also controls the rock wettability. If oil encroaches into pore spaces first, the rock behaves like an oil wet initially until water starts to enter the pore spaces. With water intrusion, gradually most of the rocks transform to mixed wet [16, 17]. Based on the mineral composition, rocks possess different charges, which also affects wettability [18].

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Carbonate rocks behave as oil wet wherein water resides in the fractures not in the rock matrix. However, increasing temperature pushes water to migrate to the rock matrix from the fractures. This transition helps enhance oil recovery from carbonate reservoirs [19-21]. Bacterial actions (*Bacillus persicus*) expedite wettability alteration in fractured oil wet carbonate rocks [22]. The appropriate aging time for wettability alteration is still unclear. Lithology, initial wetting condition, temperature of aging and compositions affect the microscopic wettability alteration. Sandstone rocks require a longer aging time (three times longer) than their counterpart, i.e., the carbonate rocks [23]. Furthermore, liquid viscosity influences the rate of oil film coating on solid rock surfaces. Surfactant rich liquid accelerates liquids' adsorption on rock surfaces [24]. Contact angle (CA) analysis shows that water wetting is enhanced as temperature rises, while reverse wetting becomes obvious at higher temperatures [25, 26].

To achieve the wetting alteration to water wet, one must first dilute the heavy oil to a lighter one for easy mobilization. Applying a solvent to heavy oil is the most recommended. Alkaline solutions, low-salinity water floods, and surfactants (anionic/cationic) may be utilized to produce from oil-wet reservoir rock [27, 28]. Ionic liquids effectively alter the wettability of oil-wet reservoirs [29-31]. Oil recovery can be greatly increased by controlling the temperature at which a solvent interacts with heavy oil and the order in which that interaction occurs [32].

Low-permeability sandstone achieves intermediate wet in wells with water cut problems. Thermally induced silane polymerization procedures decrease water cut while simultaneously increasing incremental oil recovery [33]. Apart from the aforementioned concerns, SARA (saturate, aromatic, resin, and asphaltene) analysis determines the stability of crude oil by analyzing its asphaltene content. Asphaltene tends to precipitate from hydrocarbon liquids and creates blockages in the wellbore or formation, which can negatively impact the performance of low-salinity water flooding [34]. The interlink between temperature and water flooding performance is attributed to pore geometry and wettability [35-38].

In this study, core plugs from crude oil-producing porous media were employed to analyze the recovery performance at temperatures of 65°C, 75°C, 85°C, 95°C, and 105°C. The objective of this study is to evaluate the recovery efficiency under diverse temperature conditions, considering 897 ppm and 8000 ppm salinity solutions for flooding. Past studies did not consider temperatures, salinities, and SARA analysis findings into a single experimental study. This study employs core plugs with varying mineral compositions (quartz, feldspar, kaolinite, illite, smectite, and chlorite) [39]. Resemblances to real reservoir conditions make the generated data reliable and useful. The above factors make this study novel. The findings of this study highlight the impact of temperature and salinity on enhancing crude oil recovery. The experimental works incorporated in this study are presented in **Figure 1**.

2. METHODS

2.1. Materials

This study employs a few sandstone core samples belonging to Tipam and Barail formations in India. The core sample is actual crude oil producing porous media. The reservoir crude oil analyzed is from a producing oil well in the upper Assam Basin. Each flooding process is done at five different reservoir temperatures. Oil recovery efficiency was determined by undertaking a core flood at different temperatures. SARA analysis was performed in this study to find out the asphaltene content in the crude oil sample. These findings shed light on the oil-wetting properties of the reservoir rock. Separation of crude oil from formation water (FW) was done following three sequential processes that include, firstly, the gravity separation,

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followed by centrifuge, and filtration of the formation water from crude oil [40]. The results of ion detection in FW are presented in **Table 1**, and crude oil characterization in **Table 2**. Petrophysical properties such as porosity were determined using a Helium Porosimeter, and absolute permeability using an air permeameter. The petrophysical property determination results are presented in **Table 3**.

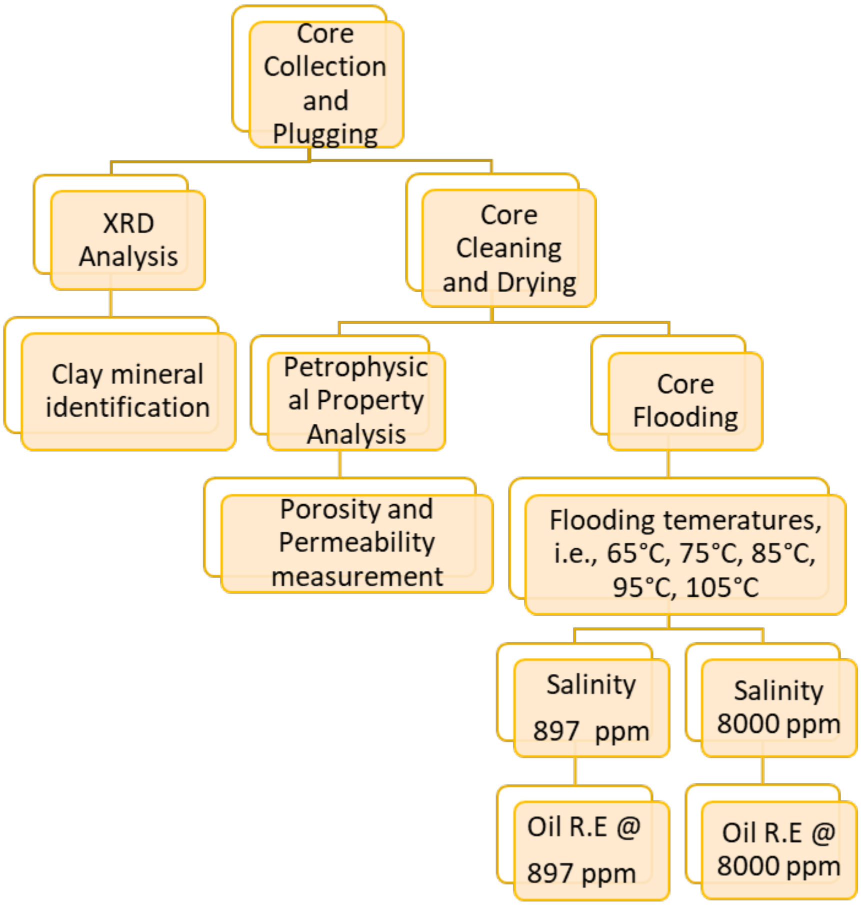

Figure 1. Experimental work design.

Table 1. FW analysis.

Property	Measured value
Major Ionic components	
Sodium as Na^+, (mg/L)	897
Potassium as K^+, (mg/L)	Nil
Calcium as Ca^{++}, (mg/L)	35
Magnesium as Mg^{++}, (mg/L)	40.2
Iron as Fe^{++}, (mg/L)	0.38
Zinc as Zn^{++}, (mg/L)	Nil
Fluoride as F^-, (mg/L)	0.79
Copper as Cu^{++}, (mg/L)	Nil
Carbonate as CO_3^-, (mg/L)	127
Bi-carbonate as HCO_3^-, (mg/L)	5939
Total Dissolved Solids, (mg/L)	5129
Salinity (ppm)	2490
pH	8.7
μ @ 25°C	1.24
μ @ 60°C	0.68

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Table 2. Crude oil characterization.

AN	BN	ρ	μ	Specific gravity	Viscosity	Pour point	Asphaltene	°API
(mg KOH/g)	(mg/KOH/g)	(g/cm^3) @15°C	@15°C	@60°F	cP (40°C)	°C	% (w/w)	@60°F
0.17	1.67	0.7996	0.8874	0.8897	2.9	27.0	0.198	28.4

Table 3. Petrophysical properties.

Core ID	Diameter, D in.	Grain Volume, cm^3	Porosity, φ, %	Permeability, k, mD	Grain Density, ρ_{mg}, gcm^{-3}	Rock Type, RT
CS	1.468	59.85	30.54	598.14	2.69	Sandstone

2.2. Methods
2.2.1. Petrophysical analysis

The core samples obtained from the upper Assam oil field were initially subjected to surface cleaning. Then, the samples were plugged into 1- and 1.5-inch diameter containers to measure porosity and permeability, respectively. The plugged samples were subsequently placed in a round-bottom flask in a Dean-Stark apparatus for cleaning with a mixture of solvents (methanol and toluene) in a 1:1 ratio. The cleaning process in the Dean-Stark apparatus was continued for approximately 72 h until refluxing of the clean solvent mixture was observed. After cleaning, the core plug samples were placed in an ultrasonic cleaner for 30 min to remove any surface contaminants. Finally, clean samples were dried in a humidity-controlled oven for 72 h. The bulk volumes of the dried samples were measured by using the physical dimensions of the plug samples. TPI-219 Helium porosimeter by Coretest System Inc. US was employed for porosity measurement. This specific method relies on Boyle's law double-cell technique to evaluate the grain volume. Absolute permeability was determined using the Ofite Model 360 air permeameter, manufactured by OFI Testing Equipment, Houston, Texas.

Table 3 presents the results obtained with the TPI-219 Helium Porosimeter and the Ofite Model 360 Air Permeameter**.** The results represent average values of the porosity and permeability investigations that were conducted in five different core samples collected from the same porous media.

2.2.2. Thin section and XRD analysis

Thin section study provides a comprehensive analysis of Tipam and Barail formations. The primary aim is to identify and examine the various clay minerals present in the reservoir, and understand its properties. In addition, XRD analysis was conducted. The results of semi-quantitative determination of clay minerals or the rock mineralogy by XRD are presented in **Table 4**. However, this study specifically considers CS porous media for subsequent analysis. The methodology used for bulk mineralogical analysis involved direct run of the (received) powdered sample using Rigaku X-Ray diffractometer (Model Ultima-IV with Ni-filtered Cu Kά radiation) with 2θ ranging from 3° to 60°. The diffractogram, so generated, is a plot of 2θ vs intensity and is interpreted by the Reference Intensity Ratio (RIR) method with the help of standard reference patterns provided by the International Centre for Diffraction Data (ICDD). Such interpretation helps identification of minerals present in a powdered sample and provides semi-quantitative estimation of their bulk abundance.

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Table 4. Rock mineralogy.

Sample Details		Minerals (%)															
		Felsic				Mica		Heavy		Carb.	Evapo.		Clay				
S. No.	Sample ID	Quartz	Microcline	Albite	Labradorite	Muscovite	Biotite	Siderite	Pyrrhotite	Calcite	Barite	Gypsum	Kaolinite	Chlorite	Corrensite	Montmorillonite	Chlorite-montmorillonite
Tipam																	
1	S5	90.8	0.6	3.4			0.4	0.3					1.0	3.2		0.3	
2	CS	77.8	6.4	5.7	0.9	0.5	1.1	1.8					5.8				
3	S3	91.5	0.4	2.4		0.4	1.2				0.5		1.1		2.5		
4	S1	80.4	4.7	8.0			0.8						1.1	3.0	0.8		1.2
5	S2	82.5	1.3	4.4	0.7	0.9	1.3	0.5		5.4				2.2	0.7		
Barail																	
6	B1	66.0	5.4	14.7	9.0	1.3	0.6					0.7		1.6			0.6
7	B2	69.5	1.6	25.0	0.8	0.7	1.2								0.9	0.3	
8	S4	94.3		1.1		1.4	0.4	1.0	0.3				1.6				
9	S6	94.5	1.9	0.5		0.8	0.8	0.3			0.3		1.0				
10	S7	87.7	1.0	2.3		0.8	1.7		0.4				1.3	4.1	0.6		
11	S8	95.9	0.7			1.3	0.7							1.4			

2.2.3. Core flooding

The arrangement for conducting the core flooding analysis is shown in **Figure 2**. A hydraulic pump is used to push oil and brine water separately into core plugs. The core plug holder used is the Hassler type. This holder is placed inside a temperature-controlled oven. Overburden pressure is kept constant during flooding with a rubber sleeve. These rubber sleeves keep the core plug inside of them. The sleeve placed within holds and directs the injected fluids solely via core plugs. The annulus between the sleeve and the surface of the core plug is prevented from leaking by the overburden pressure. A heat source equipped with a thermometer was fixed to the core flooding chamber (oven) to ensure that the core plugs remained at an appropriate temperature during the flooding process. The core flood setup included an electronic screen and a back-pressure regulator (BPR) to display the system outlet pressure and internal temperature of the core holder. Real-time data collection for the core flooding process was performed using a connected computer.

2.2.4. Wettability analysis

A wettability measurement system procured from M/s. Kruss GmbH, Germany, was deployed in this study to evaluate the contact angle, which serves as an indicator of the wetting rock characteristics. Wettability is the liquid dispersion on a solid surface pushing away another immiscible liquid. The dispersion angle is the contact angle (CA). The CA ranges from 0°to 30°denotes strong water wetting, whereas a range of 30°to 75°suggests moderate water wetting [41]. A contact angle between 75°and 90°signifies a transition zone in which the rock tends towards neutral or oil-wetting conditions in the reservoir. Contact angles above 90 °indicate predominantly oil wetting conditions. To perform the experiment, subsurface Tipam sandstone cores from oil-producing reservoirs were sliced into approximately 10 mm

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thick sections. The core plugs aged in crude oil for two weeks at the reservoir temperature. Subsequently, the analysis was carried out with brine solutions of two different salinities at reservoir temperatures of 65°C, 75°C, 85°C, 95°C, and 100°C. In this study, brine liquid drops were released onto solid rock surfaces to determine the liquid spread, thereby providing insights into sandstone rock wettability. **Figure 3** shows a a CA measurement system using M/s. Kruss GmbH, Germany.

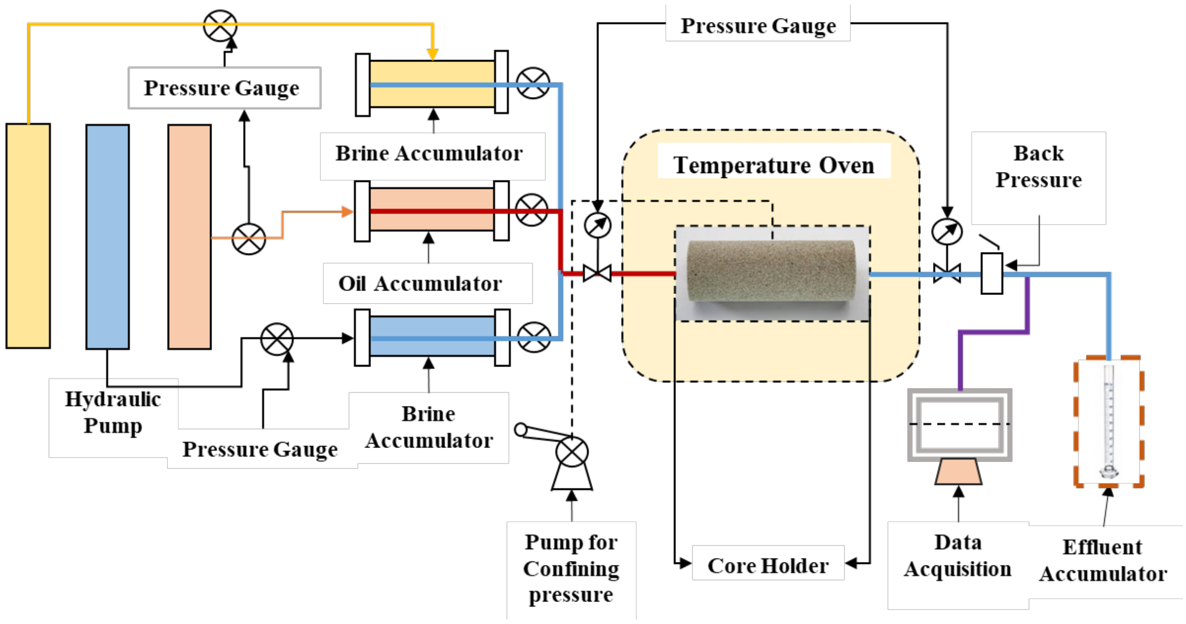

Figure 2. Schematic diagram of the Core flooding set up for analyzing oil recovery with respect to varying temperature and salinity.

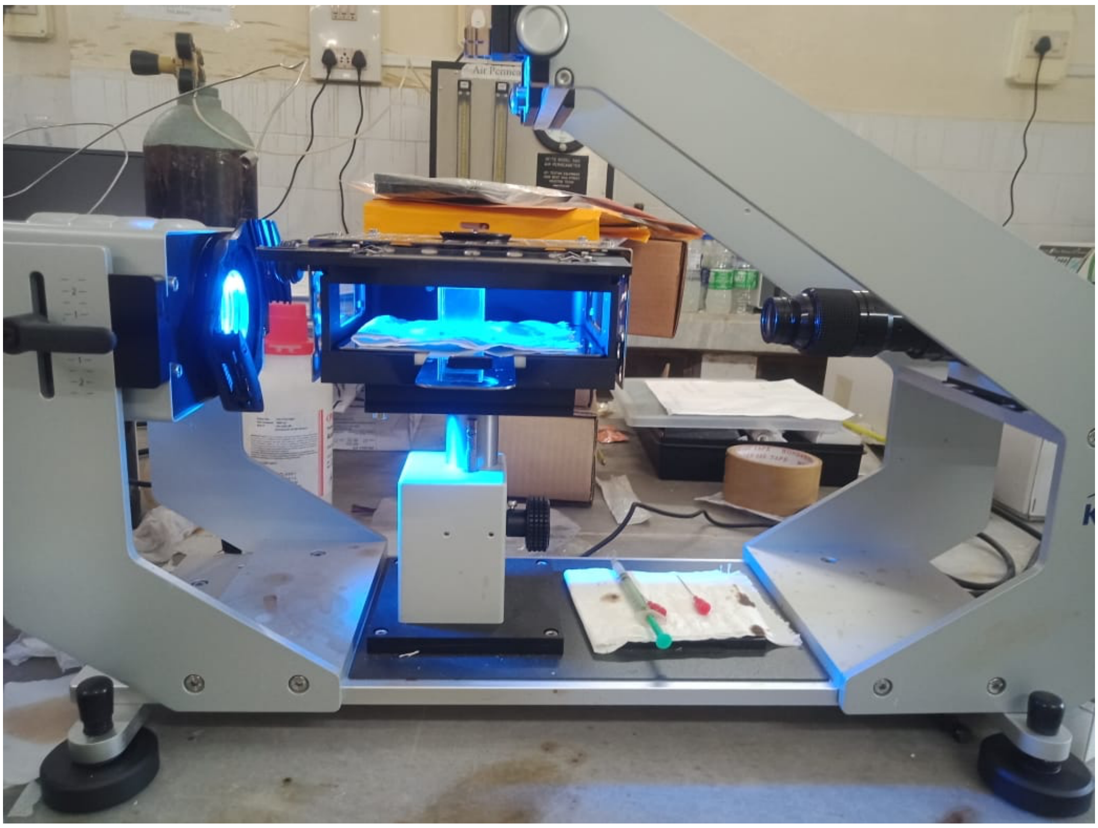

Figure 3. Contact angle measurement system, DSA.

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3. RESULTS AND DISCUSSION

3.1. Results

3.1.1. Thin section analysis

Petrographic examination suggests that the sandstone samples are primarily composed of quartz, which include both monocrystalline and polycrystalline forms (**Figure 4a**), as well as plagioclase feldspar (**Figure 4b**), with minor microcline grains (**Figure 4c**). Furthermore, some thin-section slides exhibit the presence of biotite and muscovite mica minerals, which are indented or deformed around the framework grains (**Figure 4a**). Because of the dominance of quartz in the sandstone samples, which is significantly more rigid than the other framework minerals, only minor reductions in porosity and permeability were observed during compaction. However, the presence of mechanically labile grains, such as clay clasts, low-grade metamorphic rock fragments, and feldspars, is likely to result in severe deformation owing to mechanical compaction, leading to the scattering of these grains throughout the sandstone as a pseudo matrix. This process, in turn, results in a decrease in porosity and permeability as ductile grains plastically flow into adjacent pore spaces. Matrix does not have any specific composition. It may be a mixture of quartz, feldspar, mica, etc. But its size is smaller than constituent grains of the rock.

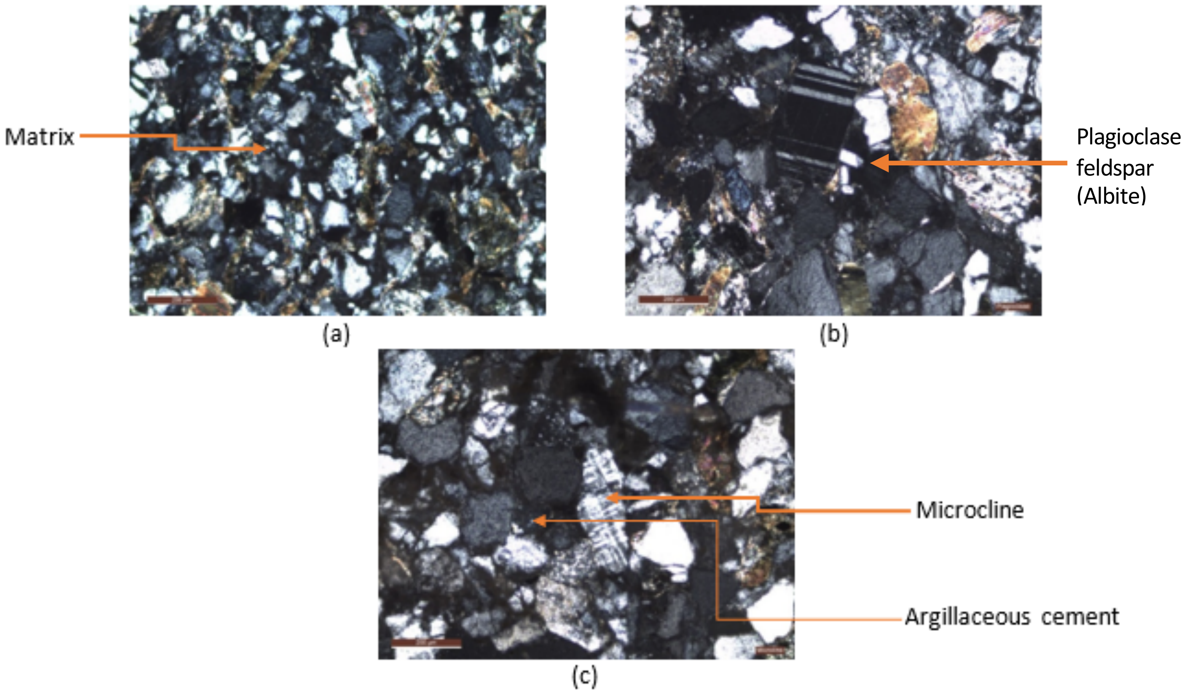

Figure 4a. Greywacke sandstone dominated by matrix content. (Magnification: 10x5); **4b.** Plagioclase feldspar embedded in argillaceous cement. (Magnification: 10x10); **4c.** K-feldspar (microcline) embedded in argillaceous cement. (Magnification: 10x10)

3.1.2. XRD analysis

Quartz appears to be the most prevalent rock-forming mineral in the studied samples, comprising approximately 77.8% of it in the CS sample. Microcline, a feldspar mineral, was the second most common mineral, accounting for 6.74% of the sample. Albite, another feldspar mineral, accounted for 5.7% of the sample, while labradorite represented less than 1% (0.9%) of the feldspars present. The analysis also identified trace amounts of muscovite and biotite mica minerals and siderite, indicating heavy minerals. Additionally, the analysis

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reveals kaolinite, a clay mineral, in an amount of approximately 5.8% in the sample **(Table 4)** and in **Figure 5**.

Bulk XRD analysis of sandstone samples from Tipam group indicates quartz as the most common rock forming mineral, ranging from 80 to 91% in most of the rock samples, followed by microcline 1-7%, albite 2-8% and labradorite <1% feldspars, muscovite <1% and biotite 1% mica minerals. Siderite 1% and calcite 5% (only in Sample No.2) represent the heavy and carbonate minerals, respectively. Barite <1% is also present as an evaporite mineral. Clay minerals like kaolinite 1-6%, chlorite 2-3%, corrensite 1-2%, montmorillonite <1% and chlorite-montmorillonite mixed layer clay 1% have been detected.

Bulk mineralogical analysis of six rock samples from the Barail group shows that quartz 66-96% is the most common framework-grain mineral in most of the rock samples. Other felsic minerals are feldspar like microcline 1-5%, albite1-25%, labradorite 1-9% and micas like muscovite & biotite 1%. Among heavy minerals, siderite 1% and pyrrhotite <1% have been noted. Evaporated minerals like barite and gypsum <1% are present in few samples. Among clay minerals, kaolinite 1-2%, chlorite 1-4%, corrensite <1%, montmorillonite <1% and chlorite-montmorillonite mixed layer clay <1% are observed in samples.

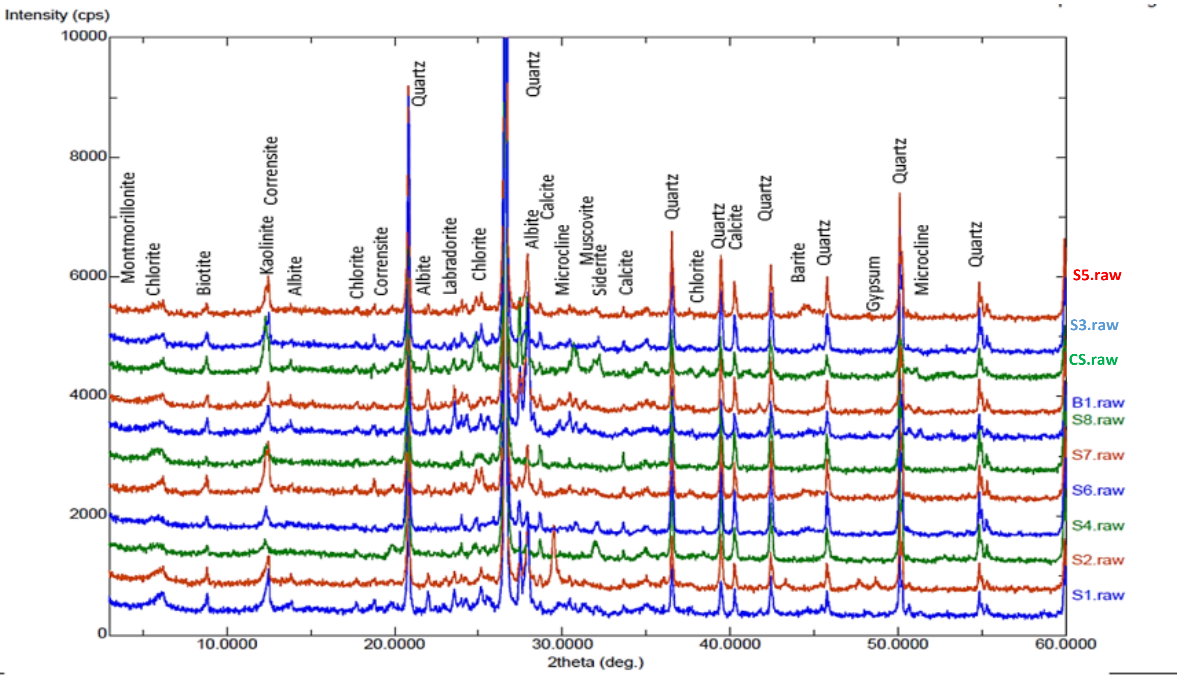

Figure 5. XRD analysis of mineral identification.

3.1.3. Core flood analysis

Temperatures ranging from 65°C to 105°C, and injection water salinity of 897 ppm and 8000 ppm were used for core flooding. This study first assessed the oil recovery efficiency for 897 ppm NaCl salinity solutions at all temperatures, which corresponds to the reservoir temperatures of five different oil reservoirs with distinct clay mineralogy, as indicated by the thin-section (**Figures 4a**, **4b**, and **4c**) and the XRD analysis (**Table 4**). Subsequently, core flooding studies for a salinity of 8000 ppm were conducted at five different reservoir temperatures. **Table 5** shows the outcomes of the core flooding at various reservoir temperatures and salinities.

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Table 5. Core flooding findings w.r.t varying salinity and reservoir temperatures.

Experiment 1: Injection water salinity for core flooding: 908 ppm				
Flooding Temperature (Reservoir Temperature)				
65°C	75°C	85°C	95°C	105°C
Oil Recovery (%)				
51.47	44.21	89.89	36.33	16.22
Experiment 2: Injection water salinity for core flooding: 8000 ppm				
Flooding Temperature (Reservoir Temperature)				
65°C	75°C	85°C	95°C	105°C
Oil Recovery (%)				
22.22	38.73	59.48	43.33	4.98

3.1.4. Wettability analysis (contact angle)

This study utilized a direct method for evaluating wettability in relation to the crude oil-rock-formation water interaction using the sessile drop technique. Crude oil recovery efficiency was analyzed at different reservoir temperatures (65°C, 75°C, 85°C, 95°C, and 105°C), with salinities of 897 ppm and 8000 ppm. The results are illustrated in **Tables 6** and **7**.

Table 6. Contact angle determination with respect to 897 ppm NaCl salinity solution at different reservoir temperatures.

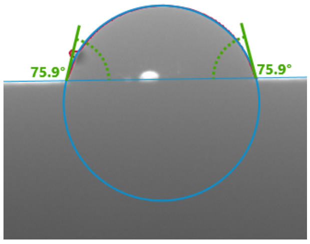
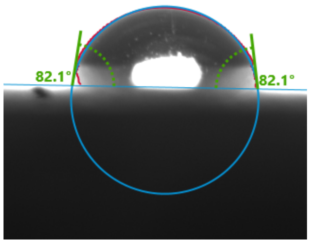
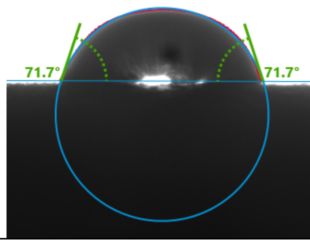
Experiment 1: Salinity: 908 ppm;	
Reservoir Temperature	**Contact angle**
65°C	
75°C	
85°C	

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Table 6 (Continue). Contact angle determination with respect to 897 ppm NaCl salinity solution at different reservoir temperatures.

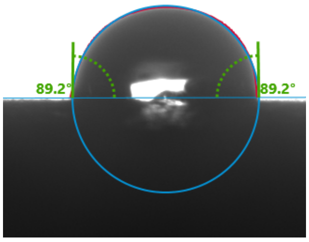
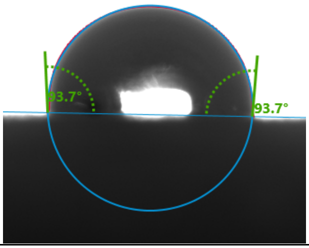
Experiment 1: Salinity: 908 ppm;	
Reservoir Temperature	**Contact angle**
95°C	
105°C	

Table 7. Contact angle determination with respect to 8000 ppm NaCl salinity solution at different reservoir temperatures.

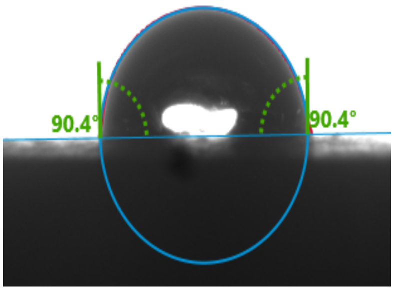
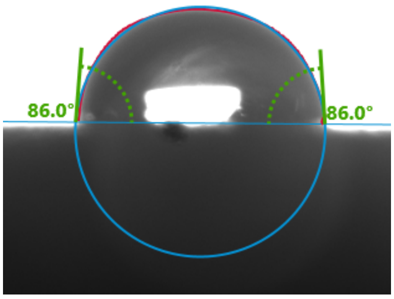
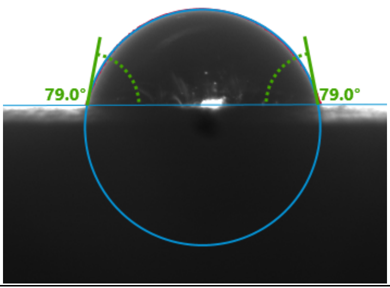
Experiment 1: Salinity: 8000 ppm;	
Reservoir Temperature	**Contact angle**
65°C	
75°C	
85°C	

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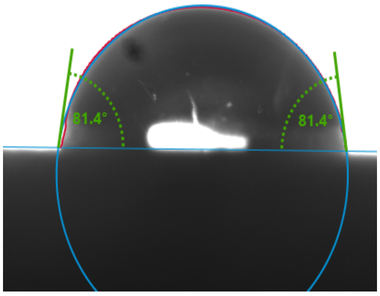
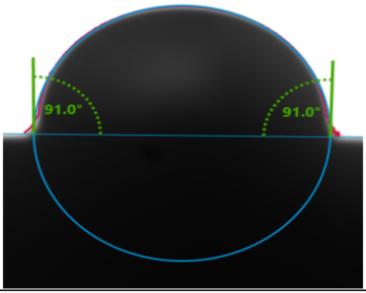
Table 7 (Continue). Contact angle determination with respect to 8000 ppm NaCl salinity solution at different reservoir temperatures.

Experiment 1: Salinity: 8000 ppm;	
Reservoir Temperature	**Contact angle**
95°C	
105°C	

The findings depicted in **Table 6** and **7** indicate that the highest oil recovery rate of 89.89% was attained at a low salinity level of 897 ppm, with the reservoir temperature set at 85°C (**Table 5**). Conversely, when the salinity was increased to 8000 ppm, the recovery efficiency declined to 59.48%. The corresponding CAs obtained with 897 ppm and 8000 ppm salinity (NaCl solution) at an 85°C reservoir temperature were 71.7° and 79°. 85°C offers the lowest CA compared to reservoir temperatures of 65, 75, 95, and 105 °C. Thus, higher water wetting is achieved at 85°C. Conversely, 105°C offers high CA, suggesting a transition from water-wetting to oil-wetting properties. The contact angles observed for the 908 ppm and 8000 ppm salinity injection water (NaCl) solutions are 93.7° and 91°, respectively.

3.2. Discussion

3.2.1. Thin section analysis

The minerals identified under thin section affect petrophysical properties as well as the mineralogy of oil reservoir formations. Key reservoir characteristics, i.e., porosity, permeability, wettability, are all affected by these minerals. Past studies show that plagioclase feldspar occurs in monocrystalline and polycrystalline grain forms. Fluid induced alteration results in increasing plagioclase content higher than muscovite and biotite. On the other hand, grain size and texture of plagioclase influence reservoir properties. Finer plagioclase replaces coarser k-feldspar, affecting deformation and its fabric mechanisms [42, 43]. Mica minerals (muscovite and biotite), through their dehydration facilitated by Quartz and k-feldspar reaction effects, influence the nature of secondary porosity. Quartz dominance influences hydrophilic behavior in sandstone making reservoir wettability towards water-wet conditions. Furthermore, its abundance in sandstone enhances porosity in the reservoir and improves pore structure and connectivity [42]. Wettability alteration is influenced by aluminosilicate minerals (K-feldspar, microcline) and plagioclase. These minerals interact with functional groups in oil like carboxyl (−COO(H)) and alkyl ($-CH_3$) on mineral surfaces. This

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adhesion behavior is key to the wettability alteration process [44]. In addition, the resultant fluid pathways in crystalline rocks affect the porosity and permeability [45]. These findings resemble the present work's findings of the thin section analyses.

3.2.2. XRD analysis

Previous studies are of the view that Quartz in sandstone promotes water-wet conditions owing to its hydrophilic behavior exhibited on the surface. Feldspar minerals (microcline, albite, and labradorite) are reactive alkalis. Plagioclase feldspars via chemical weathering and mineral dissolution influence wettability alteration. This alteration causes surface roughness and hydrophilicity. On the other hand, mica minerals (muscovite and biotite) are comprised of sheet silicates that exhibit hydrophilic tendencies, promoting water-wet behaviors caused by the adsorption of polar fluids. Likewise, the iron in biotite when gets released, facilitates wettability alterations. Likewise, siderite via dissolution and iron ion release may lead to wettability alteration. Kaolinite being hydrophilic promotes adsorption of polar compounds on the rock surface, leading to wettability alteration towards water-wet conditions. Overall, the above minerals help wettability alteration towards water-wet conditions [46-48]. The above minerals are also observed in XRD analysis; thereby, it can facilitate wettability alterations.

3.2.3. Wettability analysis (contact angle)

Previous studies observed mixed findings regarding the role of salinity and reservoir temperature in the wettability alteration. Based on contact angle and core flooding analysis, previous studies observed that diluting formation water salinities to 1/50th of original concentration, the contact angle got reduced from 158° (oil-wet) to 113° (intermediate wet), transitioning from oil wet towards water wet. Also, oil recovery increased from about 46% to 76% under increased temperature from 80°F to 250°F [49]. Thus, both parameters (salinity reduction and elevated reservoir temperature) have roles in wettability alteration [49-50]. In addition, it is observed that low salinity flooding in sandstone cores may increase the pH level in effluent brines irrespective of the concentration of clays in them. However, increased temperature may cause a drop in pH level as well as Ca^{2+} concentration in the effluent. This phenomenon is attributed to clay interaction and carboxylic acid detachment, emphasizing wettability alteration driven by rock mineralogy and brine concentration [50]. Various studies dealt with zeta potential measurements and core flooding consistently demonstrated that low salinity water flooding may result in wettability alterations [51]. Some studies demonstrated heterogeneous wettability alteration with ultra-low salinity water flooding [52, 53]. However, some studies found minimal impact of low salinity and reservoir temperature on wettability alteration [54]. The present study finds, based on core flooding and contact angle measurement analyses, the impact on reservoir temperature and low salinity flooding in promoting wettability alteration towards water-wet conditions. This approach in brown oil wells is cheaper and competitive with chemical EOR. The latter mostly functions on a wettability alteration mechanism in its attempt to revive crude oil production from brown oil reservoirs.

4. CONCLUSION

This study conducted a core flood analysis of the Tipam Sandstone formation, which is part of the crude oil-producing brown oil field in the Upper Assam Basin. The flooding temperature ranges from 65°C to 105°C. 897 ppm (NaCl) salinity was maintained for flooding.

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Following this step, an increased salinity of 8000 ppm was employed (**Table 5**). For each salinity, post flooding CA was separately measured at different reservoir temperatures (65°C, 75°C, 85°C, 95°C, and 105°C). The results are presented in **Figure 5** and **Figure 6**. This study also examined the petrophysical properties of core plug samples and rock mineralogy using X-ray diffraction (XRD) (**Table 4**) and thin-section analysis (**Figures 4a, 4b, and 4c**). Furthermore, this study characterized crude oil and formation water to integrate the results of each experimental analysis and shed light on how temperature and salinity affect reservoir wetting conditions and its production. The following conclusions are drawn:

(i) Minerals identified by XRD, such as albite, microcline, and labradorite, point toward developing cation-exchange properties promoting wettability alteration. Again, reduced water wetting is possible due to the presence of evaporite, gypsum, and 5.8% kaolinite (**Table 4**). The above combinations indicate feldspar dominance resulting in oil-wet rock behavior.

(ii) Core flooding with the same salinity fluid injection but with increasing temperatures shows varying recovery efficiency. Thus, a temperature effect is observed with varying salinities during core flooding.

(iii) Lower CA is observed in low salinity water flooding, which corresponds to the higher water-wetting condition. Low salinity is also favored in higher oil recovery.

Considering all, this study emphasizes that reservoir temperature, salinity, CA, and rock wettability all have interlinked mechanisms. With increasing salinity, oil recovery decreases for the same reservoir temperature. Alternatively, at increased temperatures, except beyond 100°C, it results in higher oil recovery. This finding validates the findings obtained in some previous research work [55]. In the present study, under the conditions of porous media, rock mineralogy, and crude oil and formation water properties, a reservoir temperature of 85°C results in higher oil recovery efficiency.

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6. AUTHORS' NOTE

The authors declare that there is no conflict of interest regarding the publication of this article. The authors confirmed that the paper was free of plagiarism.

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