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Study the Impact of Fluid Formulations on Sandstone Rocks Through Core Flooding Experiments and Uniaxial Compressive Strength Tests

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Abstract

This study uses various sandstone samples and custom-prepared fluid formulations to investigate fluid flow behavior through rock samples, employing core flooding experiments and uniaxial compressive strength (UCS) testing. The objective of the study is to comprehend the geomechanical strength behavior of sandstone reservoirs at different stages of their life cycle, such as prior to the migration of hydrocarbons from the source rock, at the time of discovery, and post-tertiary recovery methods. Four sandstone samples from the same block were chosen for the study, and their petrophysical parameters, such as porosity and permeability, were estimated. One of the samples' minerals was identified using X-ray powder diffraction. Core flooding experiments were conducted to evaluate fluid flow characteristics, while UCS tests assessed the mechanical integrity of the sandstone samples after fluid injection at various stages. The interplay between porosity, permeability to various fluids in respective samples at different stages, fluid viscosity, and rock strength was analyzed to identify critical factors influencing fluid transport and rock deformation. The results demonstrate how different fluid formulations and rock properties affect fluid flow patterns, permeability alterations, and mechanical degradation. This research provides valuable insights for optimizing enhanced oil recovery techniques, water injection strategies, and reservoir management in the oil and gas industry.

Keywords

EOR, Water flooding, Porosity, Permeability, Saturation, UCS

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1 Introduction

Rock and fluid properties play a significant role in the recovery of hydrocarbons from the hydrocarbon reservoirs. Among rock properties, porosity and permeability are essential properties describing pore space and subsurface rock formations' hydromechanical behavior. Understanding these properties is crucial for sustainable geo-energy applications and petroleum engineering applications across various areas, including geological sequestration, wastewater, radioactive waste disposal, etc (Kim & Makhnenko, 2020). In situ, stress conditions affect the pore structures and fluid flow paths of the subsurface rocks (Bear, 1972; Biot, 1973; Kim & Makhnenko, 2020). The interactions between permeability, changes in pore pressure, and in situ stresses of the reservoir influence the throughput of the reservoir. Due to the production of hydrocarbons in the primary, secondary, and tertiary stages, pore pressure changes and in situ stresses also influence porosity and permeability (Teklu et al., 2012). Pore size distribution also influences the average initial oil saturation and average residual oil saturation of the sandstone reservoirs (Boukadi et al., 1994).

Fluid properties such as viscosity, interfacial tension (IFT), and wettability also play decisive roles in the recovery of hydrocarbons. Many mechanisms, properties, interactions, etc., influence oil recovery efficiency at pore and macroscopic levels (Agbalaka et al., 2008). Inside the porous media, the oil phase remained unswept due to the forces of capillary pressure. These capillary forces are directly related to the wettability and interfacial condition of the rock surface (Hezave et al., 2013; Mokhtari et al., 2019; Zhang et al., 2012). Capillary pressure plays a significant role in the micro-scale of the reservoir. Snap-off is a phenomenon that influences crude oil recovery, which is dictated by pore wettability and pore geometry (Singh et al., 2017). The greater the exposure time of crude oil on the rock surfaces, the heavier crude oil would have a negative impact, making achieving wettability alteration difficult, as would the recovery of crude oil (McMillan et al., 2016). Due to the interaction between fluid-rock and fluid-fluid, oil recovery is majorly affected. These surface chemical interactions directly control relative permeability, capillary pressure curves, and wettability (Sharma & Filoco, 2000). Viscosity is a significant characteristic of crude oil, which influences oil recovery significantly. Due to the multi-component nature of crude oils, comprehending the individual component effects on the viscosity is quite difficult (Strelets & Ilyin, 2021). From the literature, it was found that increasing the content of saturates may tend to decrease the viscosity of crude oil and vice versa in the case of resins and asphaltenes. A decrease in the fraction of asphaltenes in crude oil could significantly reduce viscosity. More than resins, the same concentration of asphaltenes strongly increases the crude oil viscosity. Thus, the viscosity of oil is a result of the dynamic equilibrium of all its components (Malkin et al., 2016). Rocks are influenced by the saturation of fluids they contain concerning geomechanical parameters. Unconfined compressive strength and Young's modulus decrease, whereas Poisson's ratio tends to increase as water saturation increases (Muqtadir et al., 2018). More than igneous and metamorphic rocks, sedimentary rocks are highly affected by water saturation (Wong et al., 2016).

In the current study, four sandstone samples were chosen to replicate the hydrocarbon reservoirs at different stages of life. When the reservoir is in brine-saturated conditions, the post-migration of hydrocarbons (drainage conditions), EOR conditions, and how the reservoir strength varies were tried to restore using these four samples. Out of four samples, one was kept dry (S1) and used as a reference for the remaining samples. One sample was saturated with brine (R1), and the other was saturated with oil until irreducible water saturation was achieved (R2). The last sample (S2) experienced all these conditions. The main objective of this study was to ascertain the strength of the reservoir rock at different stages of life and how it contributes to the overall reservoir management and, ultimately, to the recovery of hydrocarbons.

2 Methodology

2.1 Sample collection and preparation

Sandstone samples utilized in the present study were collected from the basin. Block samples were collected. Four sandstone core samples were used in the study. Core samples were plugged using a drilling machine and cut into sizes of 3.8 cm in diameter and 8.5 cm in length using a cutting machine. The four sandstone core samples were earlier labeled as R1, R3, S2, and S3; however, the samples have been renamed as S1, S2, R1, and R2 for better clarity. The labels of the samples were also modified everywhere, including the figures and text. All samples were then kept in the oven for 24 hours to dry. Subsequently, samples were subjected to other tests. All the salts, chemicals, and solvents utilized in the study were procured from Merck Life Science Private Limited, Mumbai, India, HiMedia Laboratories Pvt. Ltd, Mumbai, India, and Loba Chemie Pvt. Ltd, Mumbai, India. All these chemicals were used as received. Crude oil samples were collected from the Cambay Basin in Gujarat, India. Brine was prepared using the water produced in the Cambay basin. An optimal 1000 ppm polymer slug was formulated for the tertiary recovery operations.

2.2 XRD

An X-ray diffraction analytical technique was used to gain information regarding the mineralogical composition of the sandstone samples. While cutting, one of the samples' leftover parts was cut into small pieces. They are then made into small pieces using a hammer. These small pieces were then crushed using an agate mortar piston until they became a fine powder that could be used for XRD. The study utilized a Bruker D8 Advance diffractometer to record the XRD patterns. While probing the sample to determine the various phases presented in the sample, this equipment features copper Kα (40 mA/40 kV) radiation for phase identification by determining peaks (Shao et al., 2017). A step size of 0.02° 2θ angle was chosen for this study. The data collection of samples taken from 10° to 100° 2θ angle. Diffrac. Eva software was used to process the generated XRD spectra.

2.3 Ultrasonic velocity measurements

The Pundit PLT 200 instrument was used to measure the sandstone samples' ultrasonic compressional wave velocity. It consists of two piezoelectric transducers and a waveform generator. Before the measurement, a thin gel was applied to coat the samples' surface to ensure optimum contact and no air gap between the sample and the transducers. Then, these transducers were attached to the sample's surface. During the measurements, optimum pressure was applied to the transducers while taking the measurements. These two transducers can work as transmitters or receivers, or both. The sandstone sample's ultrasonic velocity was determined by measuring the travel time of a pulse in the axial direction along the sample. 54 kHz frequency transducers were used for measuring the P-wave velocity (Sirdesai et al., 2019).

2.4 Core flooding experiments

Brine was prepared according to the produced water composition of one of the fields in the Cambay basin (Joshi et al., 2023). All the core flooding experiments were conducted at 60°C. Throughout the experiments, a 0.1 ml/min flow rate was maintained. The dry weights of the vacuum-dried samples were measured. Three vacuum-dried samples were placed in accumulators that contained brine. A pressure of 1000 psi was applied using syringe pumps, and the samples were kept in the accumulators for 24 hours. Samples were removed, and their saturated weights were determined. Subsequently, the porosity and pore volumes of the samples were measured based on the weight difference. After the saturation, the sample's ultrasonic velocity measurements were measured. Then, each sample underwent different core flooding experiments. For the S2 sample, the drainage and imbibition processes took place, and after that, one pore volume of polymer slug was injected. All the sample's permeability to brine was determined in the first cycle. Permeability to crude oil at the irreducible water saturation of the R2 sample, permeability to brine at residual oil saturation, and permeability to the polymer slug of the S2 sample were also determined.

2.5 UCS tests

The specimens prepared for this study maintained the dimensions for the UCS test as per the ISRM (2009) standard. The specimens S1, S2, R1, and R2 underwent an unconfined compressive test using GCTS uniaxial test setup.

3 Results and discussion

3.1 X-ray diffraction

XRD characterization was done to ascertain the mineralogy of one of the samples. Fig. 1 Shows the mineralogy of the sandstone sample. Diffrac. Eva software was used to analyze the XRD data. The results revealed that sandstone samples primarily comprised minerals such as Quartz, K-feldspar, and Kaolinite. Some trace amounts of microcline were also present in the sample.

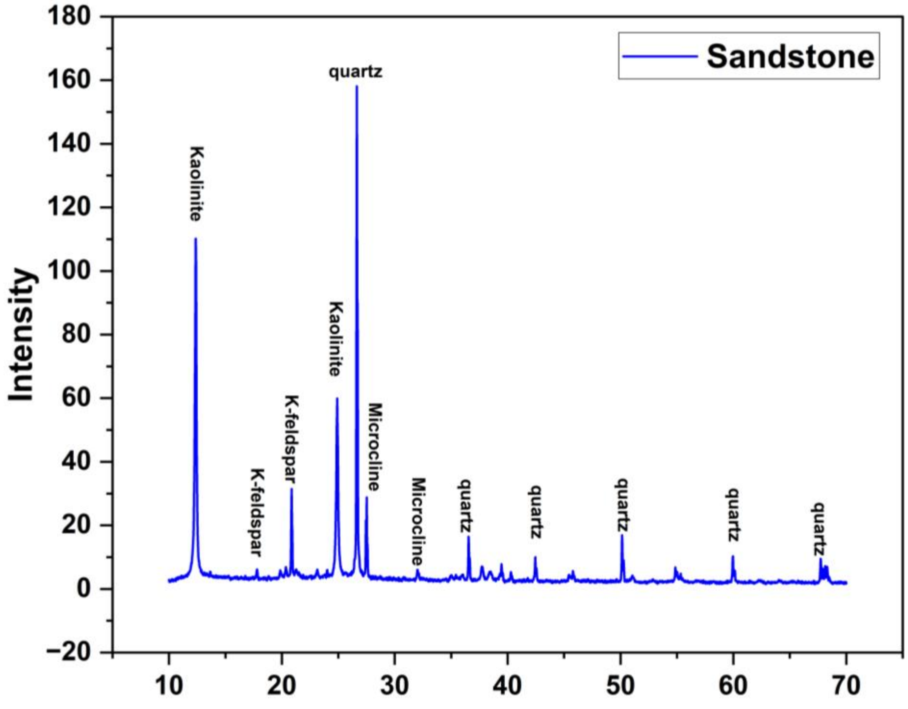

Fig. 1 XRD patterns of a sandstone sample

3.2 Ultrasonic compressional velocity

Fig. 2 Depicts the ultrasonic compressional velocities of the four samples at different stages. All the samples of ultrasonic velocities at dry conditions revealed that they all belong to the same lithology since no significant discrepancies in their velocities were observed. They are all in the range of 2300-2700 m/sec. The R1 sample was saturated with the brine, and the compressional wave velocity of this sample post-brine saturation was increased, as was the case with all the remaining samples. The increase in compressional wave velocity in the R1 samples was mainly due to the filling of pores with the brine, and it is essential to note that P-wave travels faster in water than in air (Nur & Simmons, 1969). The R2 sample's velocity post-injection of oil (drainage condition) has significantly increased. This could be mainly due to the saturation differences between oil and water in the R2 sample, which contains 80% oil and 20% irreducible saturation. The S2 sample was first saturated with brine; later, brine was displaced by oil, and water flooding was done, followed by polymer flooding for the oil recovery. As the S2 sample compared with the R2 sample, its velocity was slightly less; it could be mainly due to the presence of different fluids at different saturations because it has significant polymer slug saturation followed by water and oil saturation. The reduction in the velocity was mainly due to the polymer solution present in the sample. Due to its viscosity, the P-wave may have experienced dispersion and severe energy dissipation, which made the velocity of the velocity to be attenuated (Saxena et al., 2021).

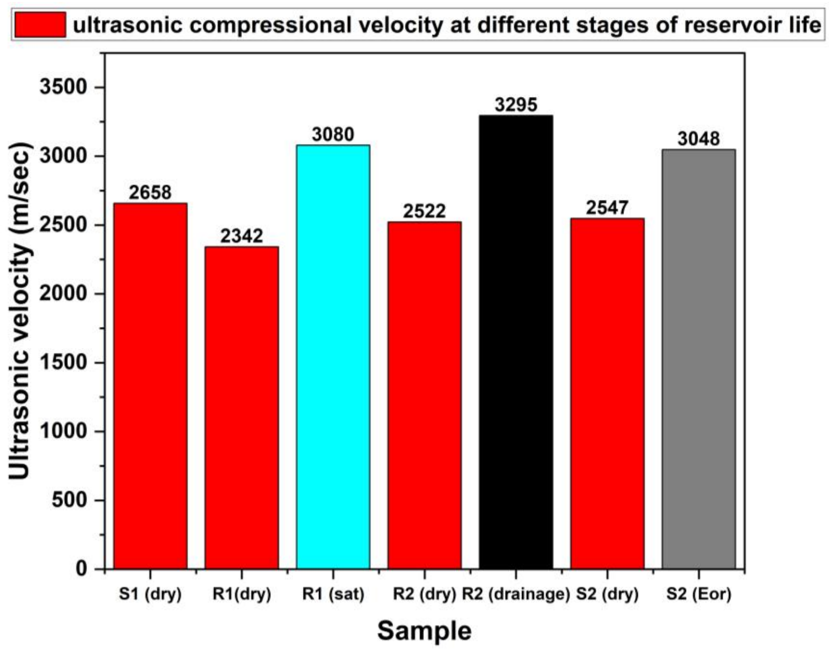

Fig. 2 Ultrasonic compressional wave velocities of all the samples at different conditions

3.3 Core flooding

Among the four samples, R1, R2, and S2 samples were chosen for the core flooding to replicate reservoir conditions. The petrophysical parameters, such as porosity, pore volume, and permeability of different fluids, were mentioned in Table 1. Since all the samples were from the exact origin and were already characterized using P-wave velocity, their porosities range from 14 to 15%. However, their pore volumes differ slightly, as seen in Table 1. Permeability to brine was also determined, and their magnitudes don't vary much. As can be observed from Table 1 When the drainage process occurred, the pressure required for the oil to displace brine increased; thus, the permeability to oil at connate water saturation was much less than its absolute permeability to brine. The same was the case with the S2 sample. In addition to that, the S2 sample has undergone secondary recovery (water flooding) and tertiary recovery (polymer flooding) methods. During the secondary flooding, brine's permeability was higher than oil's during drainage. This could be due to the lower viscosity, high brine mobility, and oil capillary trapping. Since generally oil reservoirs are water-wet in nature, brine can be easily moved through least resistance paths because of the formation of oil ganglia (Huang et al., 1995; Kazemi et al., 2022; Mohanty et al., 1987). Post-water flooding, one pore volume of polymer slug was injected into the core for mobility control and for enhanced oil recovery. It was observed that permeability to the polymer at residual oil saturation was significantly less compared to the previous oil (drainage process) and water (water flooding process). It was mainly due to crude oil's viscosity and other fluids' mobility through the rock. Various factors come into play for the mobility of different fluids through the rock samples because rock-fluid, fluid-fluid interactions, distribution of fluids, and their saturations dictate the flow and recovery. Due to all these synergistic effects of rock and fluid properties, the permeability to polymer was significantly reduced (Juárez et al., 2020). A schematic of the core flooding setup used in the current study has been shown in Fig. 3

Table 1Core flooding results

Sample	Porosity	Pore volume (ml)	Permeability to brine (mD)	Permeability to oil (Soi) (mD)	Permeability to brine (Sor) (mD)	Permeability to polymer (Sor) (mD)
R1	0.15	14.55	0.62	NA	NA	NA
R2	0.14	12.8	0.60	0.023	NA	NA
S2	0.14	12.5	0.58	0.0062	0.01	0.0053

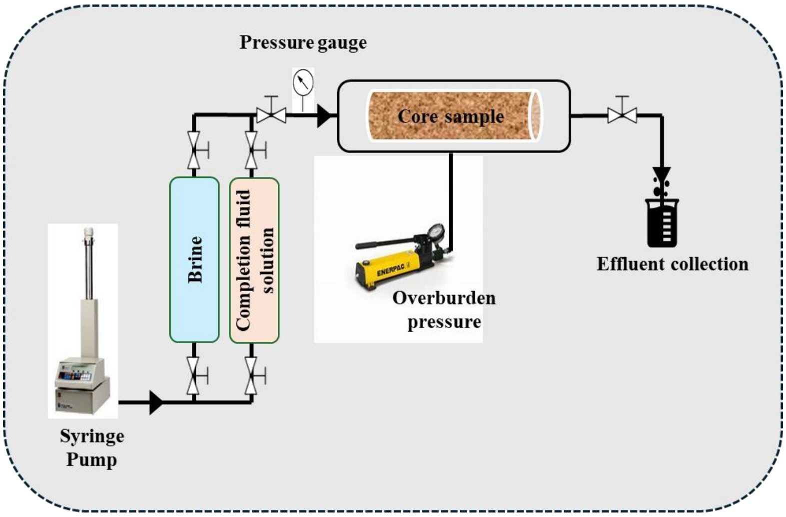

Fig. 3 Core flooding setup

3.4 UCS tests

Fig. 4 Represents the UCS procedure of all the samples used in the current study. The main objective was to understand the hydrocarbon-bearing reservoir's strength changes at different life cycle stages. So, unconfined compressive strength tests were conducted. The results revealed that the S1 sample (dry) has a higher compressive strength than the remaining samples. The R1 sample was saturated with brine, which could be a reservoir replica before the hydrocarbon migration. Its UCS strength was decreased significantly due to the saturation of brine, from which it can be ascertained that reservoir rock (sandstone) in saturated condition possesses less strength (Muqtadir et al., 2018; Wong et al., 2016). This result was aligned with the ultrasonic compressional wave velocity results. The R2 sample was similar to a hydrocarbon-bearing undiscovered reservoir. Post UCS test, it was found that the sample's compressive strength was significantly improved more than the R1 sample. It may be due to the oil saturation and connate water saturation. Since oil has more viscosity than water, it might have supported the load, and in response, it wouldn’t have reversed the load as much as water did in the R1 case (Geremia et al., 2021; Zhong et al., 2019). The S2 sample may mimic the actual life cycle of the reservoir. Water flooding and polymer slug injection were performed on the sample. After all these procedures, the UCS test was conducted. UCS test revealed that the strength of the sample was reduced compared to drainage conditions. However, its strength remained higher than that of the sample R1. As S2 might have different fluids such as water, oil, and polymer with different saturation, which may have resulted in reducing the strength of the sample compared to the R2 sample (Sheng et al., 2015).

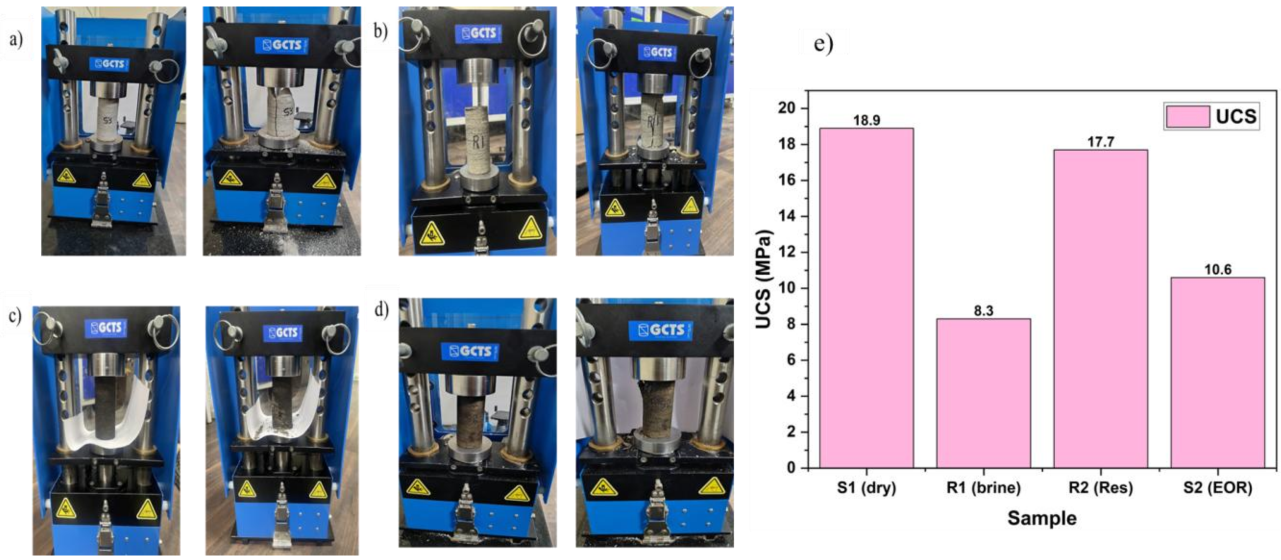

Fig. 4 UCS of all the samples a) S1 sample, b) R1 sample, c) R2 sample, d) S2 sample, e) UCS of all the samples at different stages of reservoir

4 Conclusion

Porosity and permeability are critical for understanding subsurface rock behavior, influencing hydrocarbon recovery. In situ, stress conditions and fluid interactions significantly impact these properties. Capillary pressure, wettability, and viscosity govern fluid flow in porous media. High-viscosity fluids like oil support loads better than low-viscosity fluids like brine. Polymer injection in enhanced oil recovery shows low permeability at residual oil saturation due to polymer viscosity. Rock-fluid and fluid-fluid interactions and fluid saturation levels dictate recovery efficiency. Geomechanical test results may vary from field to field depending on the mineralogical composition of the rocks and complex rock fluid interactions. However, in our study, water saturation weakens sedimentary rocks, reducing compressive strength and altering mechanical properties. Conversely, oil saturation can enhance compressive strength by supporting the load better. Understanding these dynamics is crucial for optimizing recovery methods and managing reservoirs effectively.

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