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Enhanced Oil Recovery in Fractured Reservoirs

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1. Introduction

In this chapter oil recovery mechanisms in fractured reservoirs will be reviewed and discussed. Most attention will be devoted to experimental studies on fluid flow in fractured reservoirs and imaging techniques to visualize fluid flow in-situ. Special focus will be on complementary imaging in the laboratory, where important processes in fractured reservoirs are studied at different length scales over a range of 5 orders of magnitude. A solid understanding of the flow functions governing fluid flow in fractured reservoirs provides the necessary foundation for upscaling laboratory results to the field scale using numerical simulators. The fact that numerical models and reservoir simulators are based on observations from hydrocarbon producing field and laboratory tests demonstrates the need to study the same process at different length scales. It also illustrates the close link between experimental and numerical efforts and the need for interdisciplinary knowledge to constantly improve the representation of fractured reservoirs and the predications made.

2. Naturally fractured carbonate reservoirs

Naturally fractured carbonate reservoirs are geological formations characterized by a heterogeneous distribution of porosity and permeability. A common scenario is low porosity and low permeability matrix blocks surrounded by a tortuous, highly permeable fracture network. In this case, the overall fluid flow in the reservoir strongly depends on the flow properties of the fracture network, with the isolated matrix blocks acting as the hydrocarbon storage. Most reservoir rocks are to some extent fractured, but the fractures have in many cases insignificant effect on fluid flow performance and may be ignored. In naturally fractured reservoirs, defined as reservoirs where the fractures have a significant impact on performance and oil recovery, fracture properties should be evaluated because they control the efficiency of oil production. Fractures are usually caused by brittle failure induced by geological features such as folding, faulting, weathering and release of lithostatic (overburden) pressure (Miller, 2007). Fractured reservoirs may be divided into categories characterized by the relationship between matrix and fracture properties such as permeability and porosity. Allen and Sun, 2003 defined four categories of fractured reservoirs based on the ratio between permeability and porosity in their comprehensive study of fractured reservoirs in the US as follows.

- Type I - little to no porosity and permeability in the matrix. The interconnected fracture network constitutes the hydrocarbon storage and controls the fluid flow to producing well.

- Type II - low matrix porosity and permeability. Some of the hydrocarbons are stored in matrix. Fractures control the fluid flow, and fracture intensity and distribution dictates production.
- Type III - high matrix porosity and low matrix permeability. Majority of the hydrocarbons are stored in matrix. Matrix provides storage capacity, the fracture network transport hydrocarbons to producing wells.
- Type IV - high matrix porosity and permeability. The effects of the fracture network are less significant on fluid flow. In this type category reservoir fractures enhance permeability instead of dictating fluid flow.

The four types of fractured reservoir defined above honors the geological features related to hydrocarbon storage and the relationship between permeability and porosity. Furthermore, the production characteristics of fractured reservoirs differ from conventional reservoirs in many fundamental ways. Some of the most pronoun differences are listed below (Allen and Sun, 2003).

- Due to high transmissibility of fluids in the fracture network, the pressure drop around a producing well is lower than in conventional reservoirs, and pressure drop does not play as important role in production from fractured reservoirs. Production is governed by the fracture/matrix interaction.
- The GOR (gas-oil ratio) in fractured reservoirs generally remains lower than conventional reservoirs, if the field is produced optimally. The high permeability in the vertical fractures will lead the liberated gas towards the top of the reservoir in contrast to towards producing well in conventional reservoirs. This is to some degree sensitive to fracture spacing and orientation and the position of producers. Liberated gas will form a secondary gas gap at the top of reservoir or will expand the existing cap.
- Fractured reservoirs generally lack transition zones. The oil-water and oil-gas contacts are sharp contrasts prior to and during production. The high fracture permeability allows the rapid re-equilibration of the fluid contacts.

In the following section the main focus will be on the production of hydrocarbons from fractured reservoirs, more specifically production of oil from fractured carbonate reservoirs.

3. Recovery mechanism in fractured reservoirs

The presence of fractures dramatically influences the flow of fluids in a reservoir because of the large contrast in transmissibility between the fracture and the matrix. High permeable fractures carry most of the flow, and therefore limit the buildup of large differential pressures across the reservoir. The limited viscous forces are negative for production during e.g. a waterflood, where most of the water flows in the fracture network only and does not displace oil from the matrix blocks, leading to poor sweep efficiency and low recoveries. In this scenario, the recovery mechanism is capillary imbibition rather than viscous displacement. Counter-current spontaneous imbibition, where water in the fracture spontaneously enters a water-wet rock and oil is displaced in the opposite direction, is a key recovery mechanism in fractured reservoirs during waterflooding. The amount of water imbibed from the fracture network depends on the capillary pressure curve, which is closely correlated to the pore structure and wettability preference of the rock surface. The amount of spontaneously imbibed water into an oil saturated rock is ultimately controlled by the

capillary pressure curve, or more accurately, the positive part of the imbibition capillary pressure curve. The shape and range of the positive capillary pressure curve is dictated by the wettability.

3.1 Scaling laws and shape factor

The performance of a waterflood in a given field may be tested in the laboratory in a spontaneous imbibition test. A standard imbibition test where an oil saturated rock sample is immersed in brine and the production of oil is measured as a function of time has been used to estimate production by spontaneous imbibition in fractured reservoirs. A method to upscale the laboratory imbibition curves to the production of oil from isolated reservoir matrix blocks, with various sizes and shapes, has been studied extensively. Several scaling groups to readily use laboratory results to estimate reservoir behavior are proposed. Aronofsky *et al.*, 1958 proposed an exponential form of the matrix-fracture transfer function, and formulated an important usage of scaling groups to increase computational efficiency of simulators by several orders of magnitudes. The time to complete a simulation of oil recovery from a fractured reservoir decreased dramatically when the transfer functions for fluid flow between fracture and matrix contained the rate of imbibition with scaled dimensionless time. The use of shape factors (Barrenblatt *et al.*, 1960) related to the geometric shape of the matrix block (Kazemi *et al.*, 1976; Zimmerman and Bodvarsson, 1990) was introduced to increase efficiency of numerical simulations. Experimental evidence for the validity of the shape factor was presented by Mattax and Kyte, 1962 with a dimensionless group to scale the imbibition behavior from matrix block of the same rock type with different geometries. According to Morrow and Mason, 2001, the application of the scaling group by Mattax and Kyte are subject to the following six conditions:

- gravity effects may be neglected
- sample shapes and boundary conditions must be identical
- oil/water viscosity is duplicated
- initial fluid distributions are duplicated
- the relative permeability functions must be the same
- capillary pressure functions must be directly proportional

The effect of viscosity was included by Ma *et al.*, 1997, who experimentally showed that the rate of spontaneous imbibition was proportional to the square root of the viscosity ratio for systems with similar geometry. They introduced a new definition of characteristic length, and used the geometric mean of viscosities to modify the dimensionless scaling group proposed by Mattax and Kyte, 1962, defined as:

$$t_D = t \left(\sqrt{\frac{k}{\phi} \frac{\sigma}{\mu_{gm}} \frac{1}{L_C^2}} \right) \quad (1)$$

where t_D is the dimensionless time, k is the permeability, ϕ is the porosity, σ is the interfacial tension between the wetting and non-wetting phases, t is imbibition time, μ_{gm} is the geometric mean of the viscosities and L_C is the characteristic length defined as:

$$L_C = \sqrt{\frac{V}{\sum_{i=1}^n \frac{A_i}{X_{A_i}}}} \quad (2)$$

where V is the bulk volume of the matrix, A_i is the area open to imbibition at the i th direction and X_{A_i} is the distance traveled by the imbibition front from the open surface to the no-flow boundary. A limitation to this scaling group is that its validity was only tested for strongly water-wet systems.

3.2 The influence of wettability

Understanding the wettability effect on the spontaneous imbibition process during waterflooding in fractured reservoirs is crucial because most of the worlds known oil reservoirs are not strongly water-wet. Clean carbonate rocks (and sandstones) are naturally water-wet, even though most reservoir rocks show some oil-wet characteristics. Enhanced oil recovery techniques successfully implemented in water-wet reservoirs may not necessarily perform as well in oil-wet reservoirs as the waterflood performance is strongly dependent on the wettability of the reservoir. In an oil-wet, fractured reservoir, water will not spontaneously displace oil from the matrix, and only the oil in the fractures will be displaced, resulting in poor recoveries and early water breakthrough. In water-wet fractured reservoirs, imbibition can lead to significant recoveries. The recovery of oil from fractured reservoirs is controlled by the interaction between brine/oil/rock interaction, which again depends on the wetting and two-phase flow, the chemical and physical properties of all of the three components, fracture geometry and pore structure of the matrix (Morrow and Mason, 2001).

The impact of matrix wettability on imbibition potential is well-known and the rate of spontaneous imbibition is highly sensitive to wettability (Zhou *et al.*, 2000). A general scaling law that included the effect of wettability was proposed by Li and Horne, 2002 to predict the oil recovery by water injection in fractured reservoirs. Morrow and Mason, 2001 cautioned against implementing the wettability effect in scaling laws directly, and pointed out the difficulty to scale the rate of imbibition even in simple systems like a cylindrical tube where the issue of static vs. dynamic angles arises. Although it is appealing to represent the wettability in terms of the cosine to the contact angle and apply this directly in the scaling law, the assignment of a single effective average contact angle is not physically correct for systems where there is a distribution of contact angles (Jackson *et al.*, 2003, Behbahani and Blunt, 2005).

The impact of wettability on oil recovery by waterflooding was demonstrated by Jadhunandan and Morrow, 1995, who found a maximum recovery at moderately water-wet conditions, with an Amott-Harvey index (Amott, 1959) of $I_{w-o} = 0.2$, in Berea sandstone core plugs. Zhou *et al.*, 1995 also reported the highest recovery by long-term spontaneous imbibition (~50 days) in moderately water-wet Berea core plugs. Additional evidence for the importance of wettability on spontaneous imbibition was provided by Johannesen *et al.*, 2006 that reported a similar trend in chalk. In this crude oil/brine/rock type system the maximum recovery was shifted to a wettability index of $I_{w-o} = 0.4$ measured by the Amott test.

To understand the physics behind the wettability impact, Behbahani and Blunt, 2005 used pore-scale modeling to explain the decrease in imbibition recovery and production rates with increasing aging times reported by Zhou *et al.*, 2000. They used a topologically equivalent Berea network model and adjusted the distribution of contact angles at the pore

scale. They found that the increase in imbibition time for mixed-wet samples was a result of very low water relative permeability caused by low connectivity of water at intermediate saturation demonstrating that pore-scale modeling is a useful tool to understand the physics involved with e.g. spontaneous imbibition in mixed-wet cores. The aim of pore-scale modeling is to predict properties that are difficult to measure, such as relative permeability, from more readily available data, such as drainage capillary pressure (Valvatne *et al.*, 2005).

Additional areas where the use of pore-scale modeling is beneficial was demonstrated by Jackson *et al.*, 2003 investigated the effect of wettability variations on flow at the reservoir scale using a pore-scale network model in conjunction with conventional field-scale reservoir simulators. They successfully predicted experimental relative permeability and waterflood recovery data for water-wet and mixed-wet Berea sandstone, and found that the traditionally used empirical models for predicting hysteresis in the transient zone above the oil-water-contact (OWC) were insufficient if wettability varied with height. A significant increase in oil recovery using scanning curves generated by pore-scale network rather than the empirical models was also demonstrated.

4. Complementary imaging techniques

Designing an enhanced oil recovery project is only possible when the governing processes that control fluid flow and transport within a multi compositional oil reservoir is fully understood. Performing advanced experiments that shed light on these processes is vital for validation of numerical simulators and theoretical calculations needed to evaluate the project. An important objective for experimental reservoir physics is to contribute to numerical simulation of fluid flow within a petroleum reservoir. The governing physics that describe fluid interface interaction and flow on the pore-scale (10^{-3}m) is used as input in numerical simulators to predict flow on the reservoir scale (10^3m). However, the parameters observed to be important on the pore-scale may or may not be dominant on the field scale. By experimentally investigating the same problem at increasing length scales one is well equipped to decide how to upscale from the pore-scale to the length scale of a grid block in a numerical simulation of e.g. a waterflood in an oil reservoir. Figure 1 illustrates this approach and demonstrates the importance of a strong link and interaction between numerical simulations and experiments at different length scales to fully understand the process.

The key issue for simulating flow in fractured rocks is to model the fracture-matrix interaction correctly under conditions such as multiphase flow. Combining visualization tools with different spatial resolutions and size capabilities may dramatically increase the overall understanding of the studied phenomena. The use of three visualization techniques is described below, and demonstrates the increased knowledge when applying complementary imaging.

4.1 The micro scale

Direct visualization of fluid flow and displacement mechanisms on the pore-scale is possible by using micromodels. Micromodels are porous structures in two dimensions that are based on a real rock and are normally made of glass. The micromodel used here was etched silicone micromodels designed and manufactured by Dept. of Energy Resources

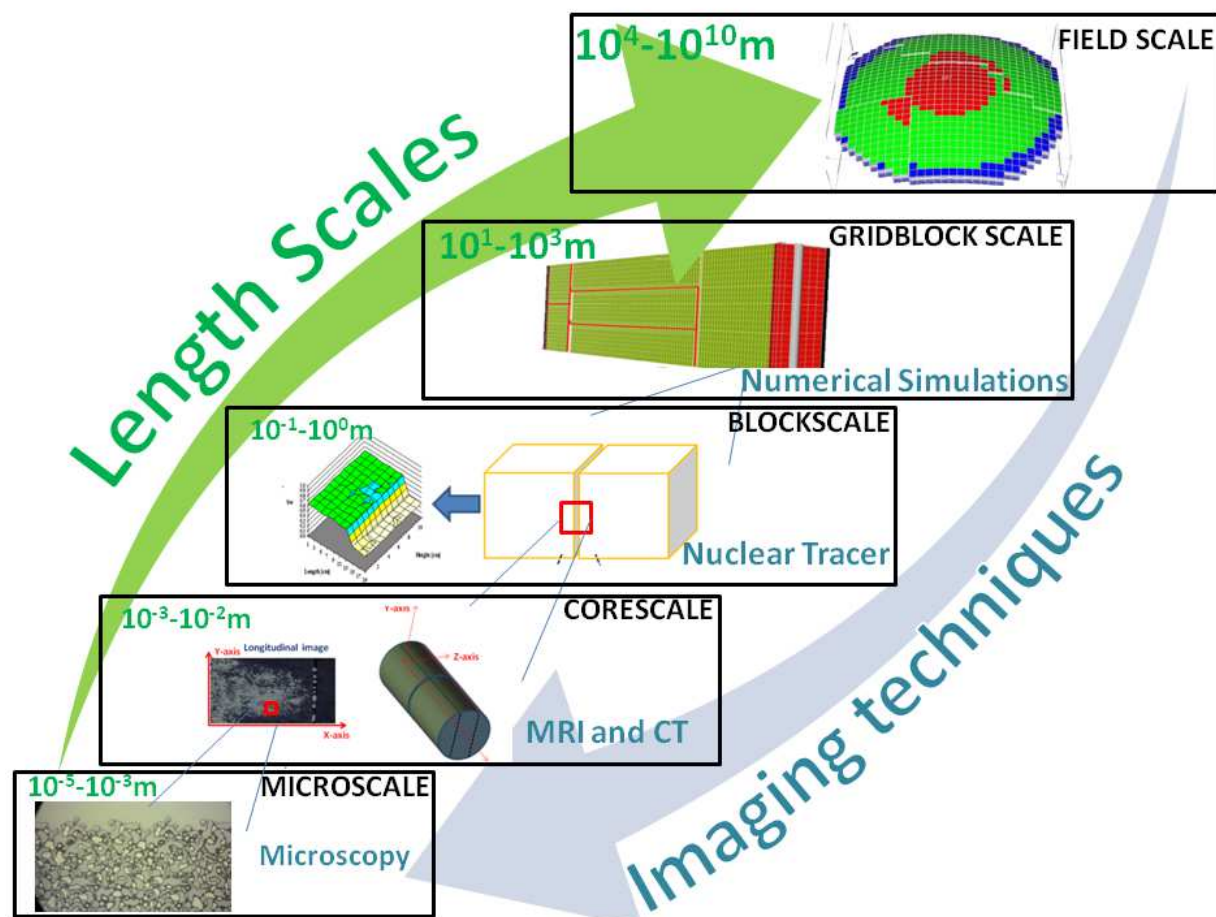


Fig. 1. Complementary imaging at different length scales.

Engineering, Stanford University. The structure of the micromodel was a 1:1 realization of the pore size and pore shapes based on a Berea sandstone thin section. The structure was etched in silicon for increased control of etching depth and accurate reproduction of fine-scale details that result in sharp, unrounded corners (Kovscek *et al.*, 2007). Average channel depth was $25 \mu\text{m}$ and sand grain features ranged between $50\text{--}300 \mu\text{m}$. The total area of the micromodel was $50 \times 50 \text{ mm}^2$, representing approximately 600×600 pores (Buchgraber *et al.*, 2011). The absolute permeability was 950 mD and the porosity was 0.47 , resulting in a pore volume (PV) of 0.013 ml . For further detail on fabrication process the reader is referred to Hornbrook *et al.*, 1991.

4.2 The core scale

Magnetic Resonance Imaging is a versatile visualization tool frequently used in hospitals and medical applications. The applications of MRI for characterizing core samples and flow properties of porous materials are also known and a considerable amount of literature has been published on the topic. MRI provides a visualization tool to study the movements of fluids inside a fracture network, and provides high spatial resolution and fast data acquisition. Previous work have discussed MRI imaging for core characterization purposes (Baldwin and Spinler, 1998; Baldwin and King, 1999), the monitoring of imbibition and displacement processes (Baldwin, 1999) and the application of MRI to the study of

formation damage. Recent studies have reported flow behavior and production mechanisms in fractured chalk and their dependency of wettability, rate and fracture aperture and fracture configurations (Graue *et al.*, 2001;Aspenes *et al.*, 2002;Aspenes *et al.*, 2008).

4.3 The block scale

The nuclear tracer imaging (NTI) technique was developed by Bailey *et al.*, 1981 and improved by Graue *et al.*, 1990, and utilizes the emitted radiation from radioactive isotopes, individually labeling the fluids to measure the *in situ* fluid saturation profiles during core flood tests. The large dimensions of the rock samples imaged is a strong advantage of this method, for instance enabling the simultaneous study of the impacts from viscous, capillary and gravity forces in a controlled fractured system. One of the advantages of using nuclear tracers is its inertness nature with respect to the delicate network of pores, assuming that adsorption is minimized by preflushing with non-radiation brine. The possibility to perform multiple experiments on the same rock sample allows for experimental reproduction and investigation of impacts on flow- and recovery mechanisms from a single parameter (e.g. injection rate, wettability or fracture). Also, the NTI technique has the capability of imaging the 1D *in-situ* oil production in cores up to 2 m in length, thus minimizing the disturbance from capillary end effects, and enabling large scale gravity drainage experiments with local saturation measurements. Details on fluid saturation calculations and experimental procedures are found in Ersland *et al.*, 2010.

5. Complementary imaging in fractured reservoirs

The production of oil is challenging in fractured reservoirs due to the large transmissibility contrast between matrix and fracture, and primary recovery is often low. The recovery efficiency depends on the relationship between the fracture and matrix permeabilities, and is strongly dependent on the wettability of the matrix, which reflects the imbibition potential of the reservoir. High demands and rising oil prices has increased focus on improved oil recovery from large, low recovery oil fields. Some of the world's largest remaining oil reserves are found in oil-wet, fractured, carbonate reservoirs. The understanding of multiphase fluid flow in oil-wet fractured reservoirs has been studied, especially the influence of capillary pressure. The presence of capillary pressure is important in recovery mechanisms like spontaneous imbibition, waterflooding, and gravity drainage. Complementary imaging techniques used to study Enhanced Oil Recovery (EOR) processes in fractured oil reservoirs have provided new and improved fundamental understanding waterflood oil recovery. MRI provides high spatial resolution and fast data acquisition necessary to capture fluid displacements that occur inside fractures less than 1 mm wide, whereas NTI provides information on macro-scale saturation distribution in larger fractured systems.

The oil recovery mechanisms involved with waterflooding fractured chalk blocks were found to be dependent on the wettability of the chalk, as the wettability had great impact on the fracture/matrix hydrocarbon exchange. The wettability was altered by dynamic aging (Fernø *et al.*, 2010) in a North Sea crude oil. After aging, the crude oil was displaced from the core at elevated temperature by injecting 5PV of decahydronaphthalene followed by 5PV decane to avoid asphaltene precipitation, to stop the aging and to establish more reproducible experimental conditions by using decane as the oleic phase throughout the

experiments (Graue *et al.*, 1996; Graue *et al.*, 1998, 1999a; Graue *et al.*, 1999b). The wettability after aging was measured with the Amott method (Amott, 1959).

Increased oil recovery during waterflooding was reported by Viksund *et al.* (1999) in fractured chalk. They used the NTI method to observe that fractures significantly affected water movement during waterfloods at strongly water-wet conditions, whereas the fractures had less impact on the water front movement at moderately water-wet conditions, where the injected water crossed fractures more uniformly, apparently through capillary contacts. The MRI images of oil saturation development inside the fractures (Graue *et al.*, 2001) demonstrated transport mechanisms for the wetting phase across the fracture at several wettability conditions, and provided new and detailed information on fluid fracture crossing previously observed in block scale experiments investigated by NTI. The high spatial resolution MRI images revealed water droplets forming on the fracture surface at moderately water-wet conditions, transporting water across the fracture.

A plausible explanation to the increased recovery above the spontaneous imbibition potential in fractured reservoirs during waterflooding was an added viscous pressure drop exerted by the wetting phase bridges across isolated matrix blocks surrounded by fractures.

5.1 Wettability effects in core plugs

Mechanistically similar to water droplets forming during waterfloods in water-wet chalk, oil was injected in oil-wet limestone cores to observe the forming of oil droplets on the surface (Fernø *et al.*, 2011). Stacked core plugs separated by 1 mm space were waterflooded, and the *in-situ* development in oil and water saturations was monitored with MRI. Figure 2 shows the wettability effect on the forming of oil droplets on the fracture surface during a waterflood in a stacked core system consisting of an inlet core, a 1mm space between the core plugs, and an outlet core plug. The space between the core plugs constitutes the fracture. Oil appears bright on the images, whereas a reduction in signal indicates increased water saturation. Each image represents a snapshot in time of the fracture, and time increases from left to right.

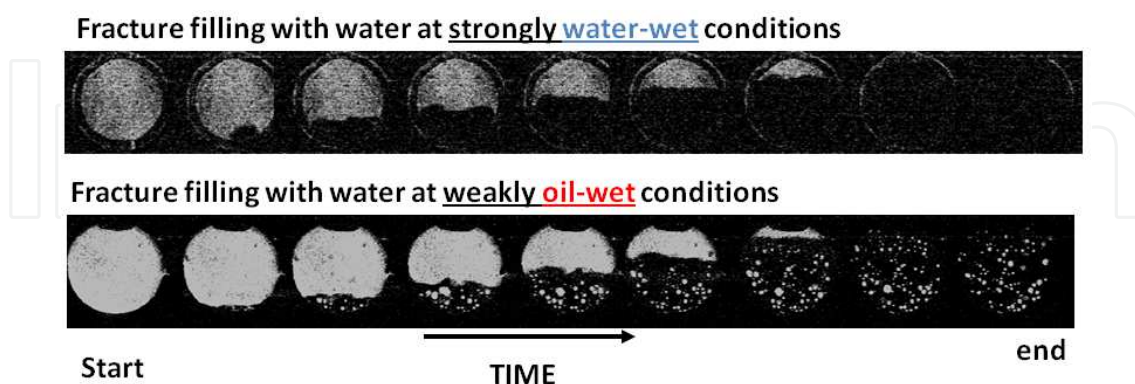


Fig. 2. The effect of wettability on the fracture-matrix fluid transfer during waterfloods in stacked core systems.

Water was injected into two stacked systems with different wettabilities. The fracture was initially oil filled, and water was injected in the core plug upstream of the fracture. Water breakthrough from the inlet plug to the fracture was observed at the bottom of the fracture.

Water displaced oil upwards and into the outlet core plug to the producer because there was no alternative escape path for the oil phase. At strongly water-wet conditions, the water filled the fracture from the bottom to the top, displacing oil in a horizontal oil-water interface. No residual oil was observed in the fracture after the water filled the fracture and invaded the outlet core plug. At weakly oil-wet conditions, water displaced the oil from the fracture similarly to strongly water-wet conditions, with a horizontal oil-water interface moving upwards. However, unlike strongly water-wet conditions, droplets of oil remained on the fracture surface after the water advanced into the outlet plug.

The locations where the droplets emerged at the fracture surface were not arbitrary, and were likely to be controlled by clusters of larger pore throats. The larger pore throats will reach zero capillary pressure before pores with narrower throats and, hence, the droplets will emerge at these locations. In the conceptual model proposed by Gautam and Mohanty (2004), the oil droplets emerged at the matrix-fracture interface in clusters of large pore throats, and, in accordance with the experimental observations made by Rangel-German and Kovscek (2006), the water transport from fracture to the matrix occurred via narrow pore throats in the vicinity of the oil producing locations. The oil droplet growth process was intermittent, i.e. a blob starts to grow, is displaced by a new blob that starts to grow at the same location and detaches from the fracture surface. Oil droplets forming on the fracture surface during displacements may be an important recovery mechanism if they bridge the fracture to create liquid bridges for oil transport and reduce the capillary retained oil in the hold-up zone during gravity drainage in oil-wet, fractured reservoirs (Fernø, 2008).

Oil was also injected through stacked strongly water-wet limestone core plugs to investigate the impact from wettability and the significance of wetting affinity between injected fluid and fracture surface on the forming of oil droplets. No oil droplets were observed in the fracture during oil injections at water-wet conditions. The hydraulic pressure in the fracture was measured during both waterfloods and oilfloods at oil-wet conditions, and the pressure development demonstrates the mechanistic difference when there is a wetting affinity between the fracture surface and the injecting fluid phase. During waterfloods, the fracture hydraulic pressure demonstrated the need to overcome a threshold value before the water invaded the outlet core, whereas no pressure increase was observed during oil injection, demonstrating the spontaneous nature of the transport of oil.

5.2 Wettability effects in block samples

The impact of wettability on the larger scale was also experimentally investigated using the NTI method and the MRI during waterfloods in fractured systems with different wettabilities. The presence of fractures dramatically changed the oil recovery, flow dynamics, and displacement processes. Three wettability conditions were tested: strongly water-wet, weakly water-wet, and weakly oil-wet. In combination with volumetric production data, the *in-situ* fluid saturation data provided information about the flow pattern with the presence of fractures to better understand the recovery mechanisms (Haugen *et al.*, 2010b). Figure 3 demonstrate the difference in waterflood behavior for three wettabilities and list the main recovery mechanisms and implications in the fractured systems. Large fractured block samples ($L \times W \times H = 16 \times 3 \times 9 \text{ cm}^3$) were waterflooded to study the effect of wettability on the waterflood behavior. Warmer colors indicate higher oil saturations.

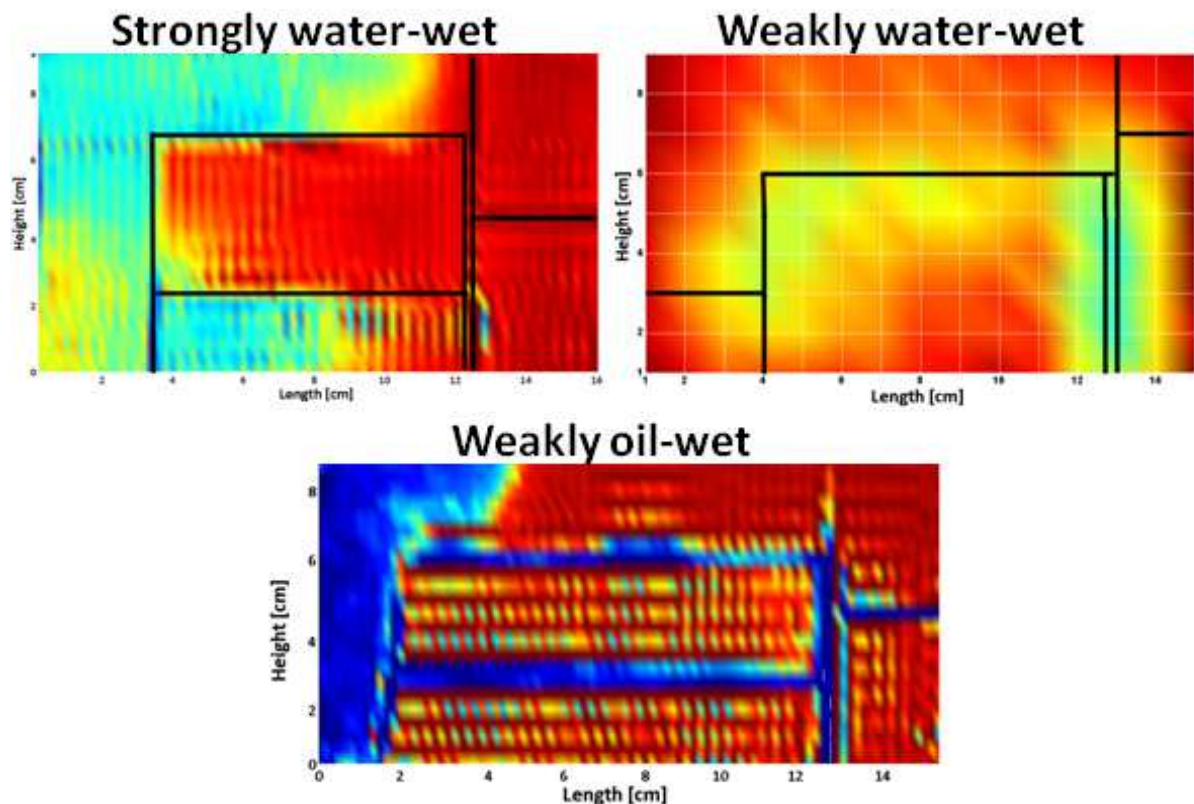


Fig. 3. The effect of wettability on the fracture-matrix fluid transfer during waterfloods in fractured block systems. Water is injected at the boundary on the left, and the direction of flow is from left to right. Fractures are indicated in black where not directly observed.

5.2.1 Strongly water-wet

In strongly water-wet systems containing several disconnected matrix blocks the fractures were barriers to flow. The displacement process was governed by capillary forces, corroborated by the visualized displacement pattern with a block-by-block displacement attributed to discontinuity in the capillary pressure curve at the matrix-fracture interface. The positive capillary pressure in the matrix block during oil displacement trapped the water phase in the matrix block until the capillary pressure at both sides of the matrix-fracture interface were equal. This occurred at the end of spontaneous imbibition, when $P_c=0$ in the matrix block. Water in the fracture network may imbibe into the adjacent downstream matrix block. Consequently, the fluid flow dynamics were strongly influenced by the presence of fractures at strongly water-wet conditions, but residual oil saturation and recovery were similar to the waterflood without fractures present. Waterflood recovery without fractures was $R_F=45\% \text{OOIP}$ compared with $R_F=42\% \text{OOIP}$ with fractures. The displacement pattern was in most cases determined by the location of the water in the fractures, and due to gravity segregation the lower blocks closer to the inlet imbibed water first. The combination of high capillary imbibition and the applied water injection rate led to the *filling regime* (Rangel-German and Kovscek, 2002) and co-current imbibition.

5.2.2 Weakly water-wet

At weakly water-wet conditions oil was recovered by capillary imbibition of water from the fractures to the matrix blocks. The interconnected fracture network limited the viscous forces in the system as the injector and producer was in direct contact, see Figure 3. The mechanism for oil recovery was purely capillary imbibition of water from the fracture. The strength of the capillary pressure to transport water from the fracture network to the matrix was reduced compared with strongly water-wet condition. The weaker capillary forces led to a reduction in matrix-fracture transfer rate and increased the likelihood of *instantly filled fracture* regime (Rangel-German and Kovsky, 2002), with counter-current imbibition of water. The presence of fractures dramatically reduced the oil recovery. Waterflood oil recovery without fractures was $R_F=63\% \text{OOIP}$ compared with $R_F=22\% \text{OOIP}$ with the presence of fractures. This demonstrates the potential to increase oil recovery in fractured reservoirs by increasing the viscous forces.

5.2.3 Weakly oil-wet

The fracture system for the weakly oil-wet block was similar to the strongly water-wet block (see Figure 3). Waterfloods were performed both before and after fractures were present, injecting water with the same rate (2 cc/hr) in both cases. The waterflood oil recovery at fractured state was $R_F=15\% \text{OOIP}$, compared with $R_F=65\% \text{OOIP}$ without the presence of fractures. In addition to a strong reduction in recovery, the fractures changed the time of water breakthrough to the producer. Water breakthrough without fractures was observed after 0.47PV injected, in contrast to only 0.10PV injected with fractures. The oil-wet wettability preference of the matrix suppressed oil recovery by capillary imbibition of water from the fracture network. Recovery was dictated by the ability to generate a differential pressure across the system. Displacement of oil from matrix only took place in the unfractured inlet block, once water entered the fracture network it rapidly filled the fractures, first the lower horizontal fracture, then the remaining fracture network before it reached the outlet. No transport of water from fracture to matrix was observed.

6. Enhanced oil recovery in fractured reservoirs

Oil production from fractured oil reservoirs poses great challenges to the oil industry, particularly because fractures may exhibit permeabilities that are several orders of magnitude higher than the permeability of the rock matrix. Low viscosity fluids used for enhanced oil recovery, such as gases or supercritical fluids may channel into the high-permeable fractures, potentially leading to early breakthrough into the production well and low sweep efficiency. Carbonate reservoirs usually exhibit low porosity and may be extensively fractured. The oil-wet nature of the matrix reduces capillary imbibition of water. Carbonate reservoirs contribute substantially to US oil reserves (Manrique *et al.*, 2007), and the low primary recovery and the large number of carbonate reservoirs in the US and around the world makes them good targets for EOR efforts.

Foam has the potential to increase oil recovery by improving areal sweep, better vertical sweep (less gravity override), less viscous fingering, and diversion of gas away from higher-permeable or previously swept layers (Bernard and Holm, 1964, Holm, 1968, Hanssen *et al.*, 1994, Schramm, 1994; Rossen, 1995). Diversion of gas into lower-permeable layers using

foams have previously been reported (e.g. Casteel and Djabbarah, 1988, Llave *et al.*, 1990, Zerhoub *et al.*, 1994, Nguyen *et al.*, 2003 *et al.*). This may be important for fractured systems, where a very large permeability contrast exists and cross-flow between the zones occur (Bertin *et al.*, 1999).

The application of foam to enhance oil recovery was studied at different length scales in fractured systems with complementary imaging techniques. Experiments were performed on the micro scale, core plug scale, and the block scale to study the use of foam in a fractured system to improve oil recovery. At the *micro scale* the mechanism for gas and liquid transport from the fracture to the matrix was investigated. Liquid snap off at the pore throat was observed as a mechanism for foam generation within the matrix, whereas large pressure fluctuations along the fracture lead to foam invasion from the fracture to the matrix. At the *core scale* the added oil recovery during foam injection compared to gas injection was demonstrated in a fracture core plug with the presence of oil in the matrix. The increased pressure drop across the fracture contributed to fluid transport from the fracture to the matrix and displacement of oil. The wettability of the core plug was weakly oil-wet reflecting the reservoir wetting preference in several large carbonate oil fields. The same process was studied in at the *block scale*, where three forces (gravity, viscous, and capillary) were active simultaneously. The injection of pregenerated foam greatly increased recovery by increasing the differential pressure across the system. Foam injection was compared to waterfloods, surfactant injection, pure gas injection and co-injection of surfactant and gas (Haugen *et al.*, 2010a). Experimental results at each length scale are described in detail in the sections below.

6.1 EOR at the micro scale

Foam injection in fractured reservoirs was studied at the micro scale using etched silicon micromodels manufactured at the Department of Earth Sciences, Stanford University (Hornbrook *et al.*, 1991; Buchgraber *et al.*, 2011). Experiments were designed to study the transport of gaseous phase from the fracture into the matrix during foam flow at a pore level. The micromodel represents an actual Berea sandstone pore space with respect to pore size distributions. The model was shaped as a square, with injection ports in each corner. Injection ports were paired and connected with a conduit that constituted a fracture. All injections were performed horizontally, without the influence of gravity. A NIKON microscope, in combination with a cam recorder, was used to visualize and store images of the displacement processes in the fracture and in the matrix during injections. The injected gas phase was N_2 , and the foam was pregenerated outside the micromodel by co-injecting gas and a standard 1wt% active AOS surfactant solution in a Berea sandstone core plug. Foam generation in silicon micromodels was previously reported by Kovscek *et al.*, 2007.

Figure 4 shows the displacement process during a pure gas injection (left column) and foam injection (right column) in a fractured reservoir. The fracture was located at the top of the image and in direct contact with a porous structure. Both fracture and matrix were initially fully saturated with surfactant solution. In each image sand grains are white, the aqueous surfactant solution is blue, gas is red, and the interface between the gas and the surfactant is black. A slight backpressure was applied to reduce gas compressibility effects. Total injection rate was 4 cc/hr during both the pure gas injection and during the foam injection. The gas fraction during foam injection was 0.95. The results show that during pure gas

injection, the gas only displaced surfactant in the fracture and was not able to penetrate the matrix to displace water. During pregenerated foam injection into the fracture; the foam was able to penetrate the matrix to displace water. The gas pressure in the fracture fluctuated highly as a result of the forming and breaking of gas bubbles in the fracture. The pressure fluctuations controlled the local gas rates in the fracture, as the gas phase switched between stationary to high flow rates continuously. The fluctuating pressure and flow contributed to the amount of gas invaded into the matrix. Surfactant in the matrix resided in the smallest pores and in corners.

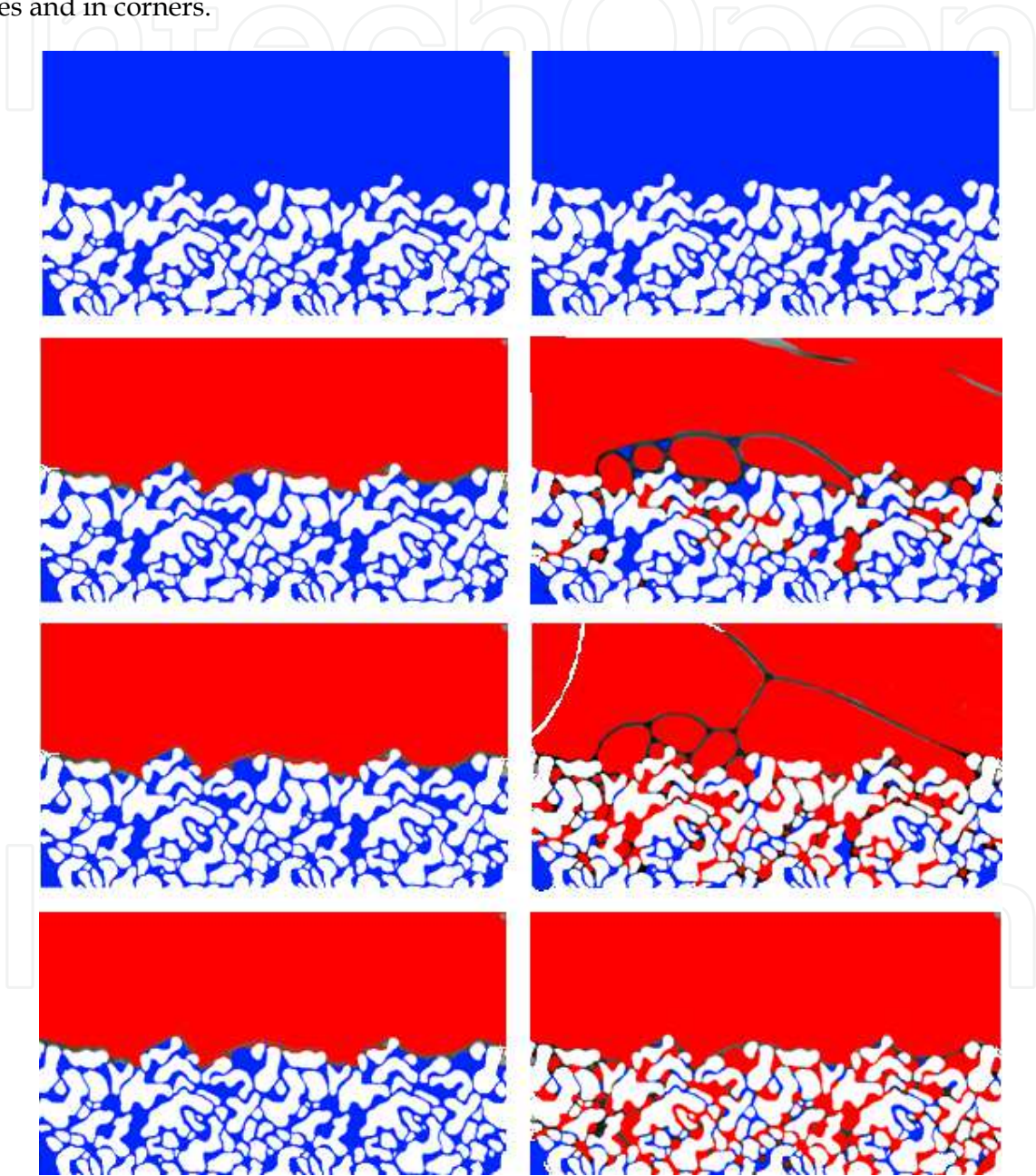


Fig. 4. The effect of foam on the transport of gas from the fracture to the matrix. Left column: pure gas injection with gas flow was only in fracture. Right column: foam injection displacing water in the fracture and the matrix. In each image, sand grains are white, the aqueous surfactant solution is blue, gas is red, and the interface between the gas and the surfactant is black.

6.2 EOR at the core plug scale

Foam experiments in a fractured limestone core plug (length: 7.07 cm, diameter: 4.8cm) was performed to study the use of foam as an EOR technique in fractured reservoirs. The performance of foam was compared to pure gas injection. The wettability of the matrix was weakly oil-wet. The vertical fracture (top to bottom) in the horizontally positioned cylindrical core plugs constituted a rectangular slit. The fracture aperture was not measured, but was calculated from the empirical relationship between aperture and the measured permeability. Because the core plug was cut using a circular saw with a diamond coated blade, the fracture surface was assumed to be smoother than naturally-fractured reservoirs. The two half-cylindrical core plugs were inserted into a core holder and the confinement pressure was increased until a desired fracture aperture or system permeability was established.

Figure 5 shows the oil recovery and differential pressure buildup during the gas and foam injections. The core geometry is seen in the lower right corner, with the fracture plane indicated. Two injections were performed: 1) gasflood with N₂ gas with 30 ml/hr injection rate, and 2) injection of pre-generated foam at 33ml/hr (N₂ gas fraction at 0.91).

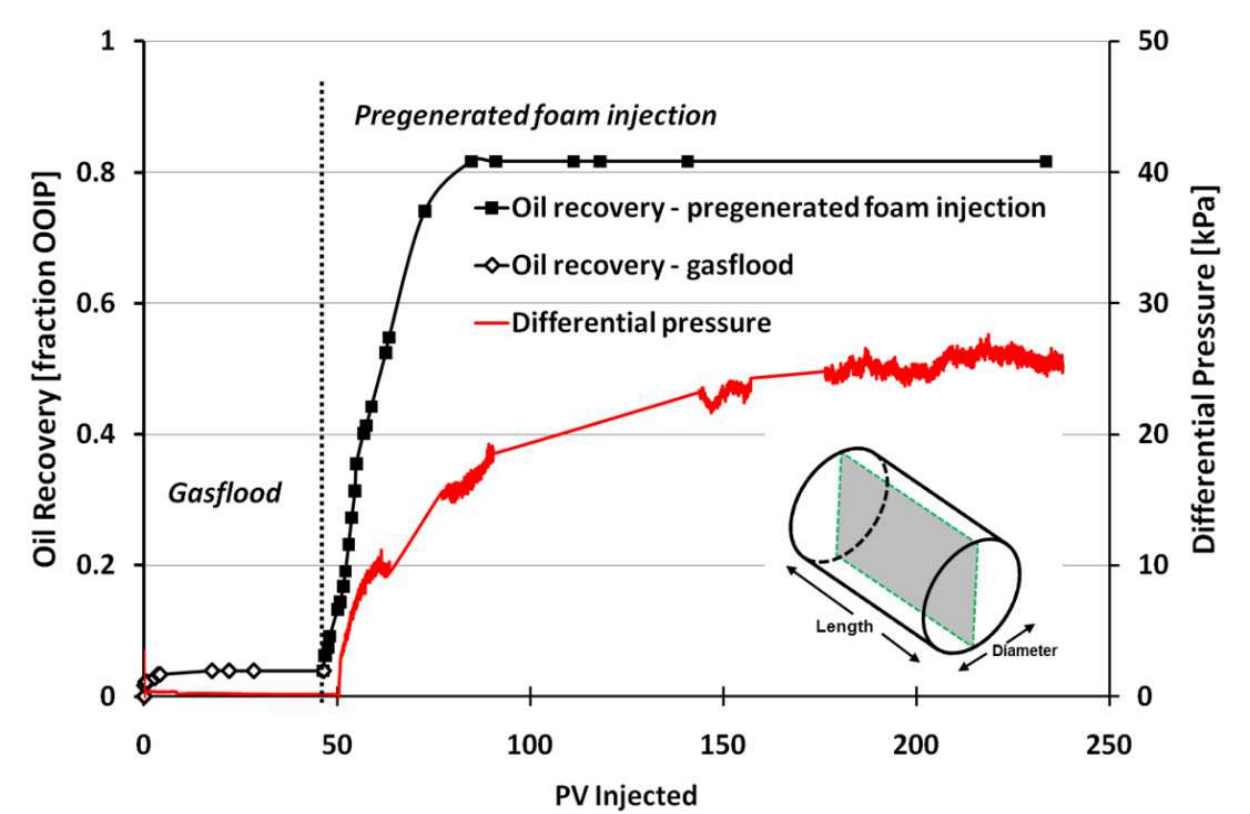


Fig. 5. The effect of foam as an EOR technique in fractured, oil-wet carbonate core plug.

Gasflood oil recovery was $R_F=4\%$ OOIP, attributed to the oil in the fracture volume of the core. No pressure build up was recorded as the pressure remained at 0.15kPa during the injection (42hrs, 49PV). Significant increase in oil recovery was observed during the pre-generated foam injection, with $R_F=77\%$ OOIP additional recovery. Oil recovery ceased after 30hrs injection (total 48PV, 43.7PV N₂ gas and 4.3PV surfactant solution), but the injection

was maintained for 170hrs (total 272PV, 247.5PV N_2 gas and 24.5PV surfactant solution). A sharp initial increase and slowly rising differential pressure, reaching maximum at 25kPa, was observed. Foam was not observed at the effluent, but rather single menisci dividing alternate bubbles of liquid and gas. Final recovery after the foam injection demonstrate the potential of this technique, but the high number of pore volumes injected to reach ultimate recovery must be improved for the technique to be successfully applied in the field.

6.3 EOR at the block scale

Foam injection as an EOR technique in fractured, oil-wet carbonate rocks was further investigated in a block sample. Oil recovery during waterflood, pure gasflood, and surfactant injection were compared with co-injection of gas and surfactant in a pre-generated foam injection. Three injections were performed: 1) a waterflood with 10 cc/hr injection rate, 2) a surfactant flood with 10 cc/hr injection rate, and 3) a pre-generated foam injection with an injection rate of 130 ml/hr (N_2 gas fraction was 0.92). Figure 6 shows the experimental setup used with a Bentheim sandstone core plug as a foam generator. The fracture network in the block sample can also be seen.

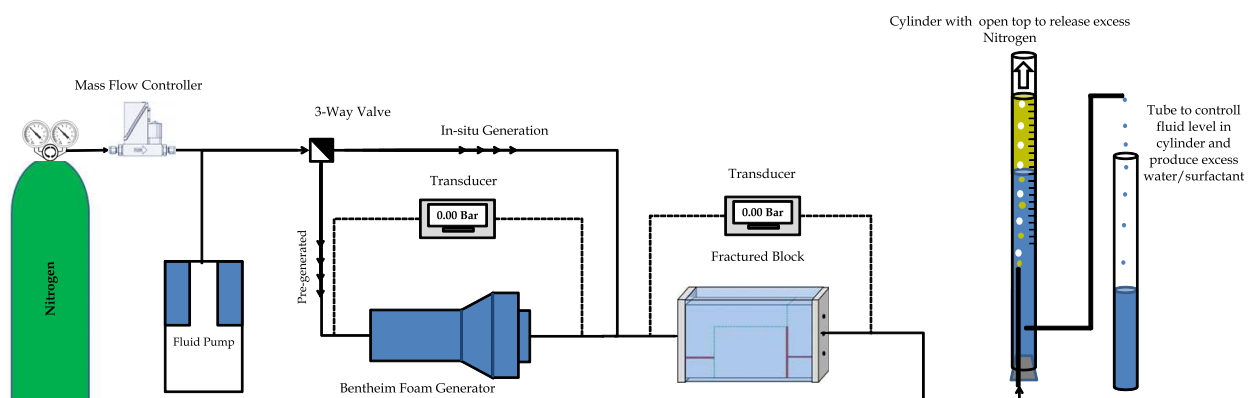


Fig. 6. Experiment setup used during pregenerated foam injection in a fractured block sample (Haugen *et al.*, 2010a).

Figure 7 shows the oil recovery for each injection and the development in differential pressure. Waterflood produced $R_F=10\%$ OOIP with a clean water-cut (i.e. no two-phase production). The subsequent surfactant injection produced an additional $R_F=2.5\%$ OOIP during 9PV injected. The pre-generated foam injection produced additional oil, amounting to $R_F=75.7\%$ OOIP, with a fast initial recovery followed by a slowly reducing oil production. Differential pressure across the block was fluctuating, with an overall increasing trend. Foam was not observed in the effluent, but rather as single menisci dividing alternate slugs of liquid and gas.

During pre-generated foam injection the differential pressure increased in all tests, and the oil production increased significantly. Foam was not observed at the outlet suggesting that foam collapsed or changed its configuration when advancing through the fracture(s). The destabilization of foam inhibited further foam front movement (Bernard and Jacobs, 1965). The mechanism(s) behind foam collapse cannot be distinguished from this work alone, but plausible mechanisms include:

- Oil intolerance
- Gravity segregation in the fracture
- Fracture wettability
- Divalent ions in the brine

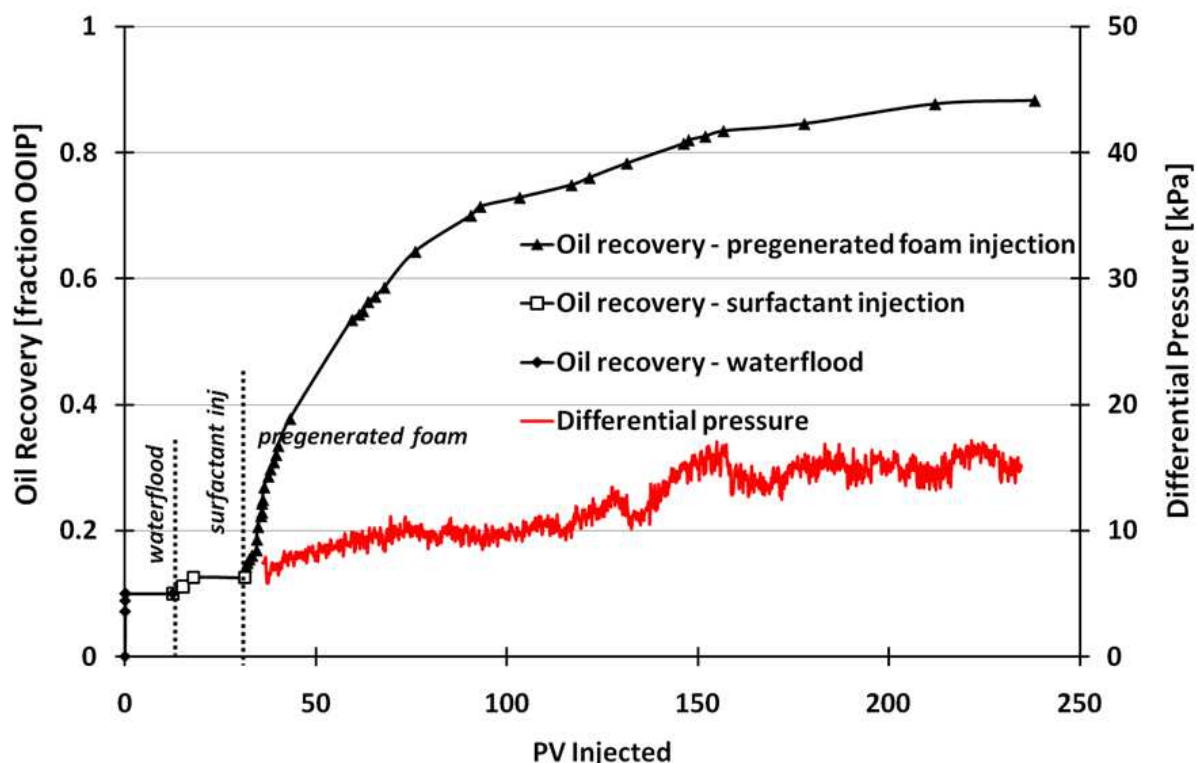


Fig. 7. The effect of foam as an EOR technique in fractured, oil-wet carbonate block sample.

6.4 EOR by foam injection in fractured reservoirs

Enhanced oil recovery by foam injection during gravity drainage was studied numerically by reducing the gas mobility (Farajzadeh *et al.*, 2010). Water and oil were produced at the bottom of the fracture at the instance they were displaced from the matrix, resulting in the fracture always being gas-filled. With decreased fracture permeability, the mobility of all fluids was reduced, increasing the viscous forces in the system. Similar results were found by Haugen *et al.*, 2008 and Fernø *et al.*, 2008 where decreasing fracture transmissibility increased oil recovery during waterfloods. In the case of foam flow in fractured media, the apparent foam viscosity is more important for oil recovery than the reduction in fracture transmissibility because increased foam viscosity leads to increased differential pressure and the increased oil recovery.

The application of foam as an EOR technique in fractured reservoirs will also lead to improved sweep efficiency. This is essential in highly heterogeneous reservoirs, where the majority of fluid flow is concentrated in the high permeable zones. Continuous foam injection at fixed injection rate may improve sweep efficiency by raising the injection-well pressure (Shan and Rossen, 2004), but the pressure increase may be undesirable in conventional, un-fractured reservoirs, where a rise in injection-well pressure could damage

the well (Shi and Rossen, 1998). For fractured reservoirs, the pressure drop generated by the low-mobility foam, extending from the displacement front back to the injection well, is an important mechanism to improve the sweep efficiency. The injection of pre-generated foam reported at the core and block scale was successful with respect to oil production, which significantly increased recovery in all samples. The process was inefficient in terms of the number of pore volumes required to recover the oil. Economically viable production rates and reduction of surfactant cost could be achieved by taking the necessary steps to reduce foam collapse, which could be caused by any of the mechanisms previously outlined. The increase of the foam tolerance to oil (Hanssen and Dalland, 1990; Dalland and Hanssen, 1993; Dalland and Vassenden, 1998; Hanssen and Dalland, 2000) is a proven method to make foam injections more efficient.

Foam injection as an EOR technique at field scale should be considered to reduce gravity override and injectivity issues. Foam injection was successfully implemented on the Norwegian Continental Shelf in the Snorre field as a Foam-Assisted-Water-Alternating-Gas (FAWAG). This project revealed that important parameters for the success of foam injectivity were surfactant adsorption, critical surfactant concentration, foam drying effect, foam oil tolerance, and foam strength (Blaker *et al.*, 2002). Foam efficiency could also be improved with smaller well-spacing (Awan *et al.*, 2008). A surfactant preflush that alters the wettability of the fracture surface (removes oil) may benefit foam stability in the fracture. In vertical fractures, care should be taken to limit gravity segregated fluid flow during co-injection of aqueous and gaseous phases. During gas injection projects, foam should be injected as early as possible after gas breakthrough (Surguchev *et al.*, 1996). Foam injection in combination with other EOR efforts may also improve economics, for instance foam in combination with ASP flooding or polymer gels (Wang *et al.*, 2006).

7. Conclusion

Complementary imaging techniques used to study EOR techniques such as waterflooding, gas injection, and foam injections in fractured oil reservoirs provide new and improved fundamental understanding of the oil recovery process. The use of complementary imaging techniques allows studying EOR processes in porous media from the micro scale (10^{-5} - 10^{-3} m) to block scale (10^{-1} - 10^0) covering 5 orders of magnitude. The combination of two imaging techniques such as Magnetic Resonance Imaging (MRI) and Nuclear Tracer Imaging (NTI) enables a complementary investigation on materials and processes, where large scale (~meters) phenomena are controlled by small scale (micrometer) heterogeneities.

MRI provides high spatial resolution and fast data acquisition necessary to capture the processes that occur inside fractures less than 1 mm wide, whereas NTI provides information on macro-scale saturation distribution in larger fractured systems. The oil recovery mechanisms involved with waterflooding fractured carbonate blocks were found to be dependent on the wettability of the matrix, as the wettability had great impact on the fracture/matrix hydrocarbon exchange. The MRI images of oil saturation development inside the fractures revealed transport mechanisms for the wetting phase across fractures at several wettability conditions, and provided new and detailed information on fluid fracture crossing previously observed in block scale experiments investigated by NTI. The forming of oil droplets of the fracture surface at oil-wet conditions mechanistically corroborated the results previously observed when waterflooding chalk at water-wet conditions. Pore scale

modeling should be considered as a tool to calculate more accurately the capillary pressure and relative permeability curves in the fracture in the presence of growing liquid droplets. This would increase the confidence in the applied multiphase functions and strengthen the overall physical understanding of flow in fractured rocks. The derived multiphase functions should be implemented in the numerical model, and the errors by not accounting for this should be understood and quantified.

The effect of capillary pressures at various wettabilities was experimentally studied at different length scales, which was used as the basis for numerical simulations of multiphase flow in fractured reservoirs. This review demonstrates the influence of capillary pressure as a vital input parameter in simulations to describe fluid flow in the reservoirs and as the dominant multiphase function for important recovery mechanisms in fractured reservoirs; such as spontaneous imbibition and gravity drainage.

Injection of pre-generated foam greatly enhanced oil recovery, with recoveries up to 80%OOIP. Increased apparent foam viscosity increased oil recovery in similar fractured systems. Enhanced oil recovery by pre-generated foam injection in fractured, oil-wet limestone was observed only after high pore volumes throughput. Oil recovery efficiency may increase by reducing the rate of foam collapse in the fractures by:

- Improving the foam oil tolerance.
- Changing the wettability of the fracture surface to water-wet.
- Optimizing the injection of foam (e.g. FAWAG).

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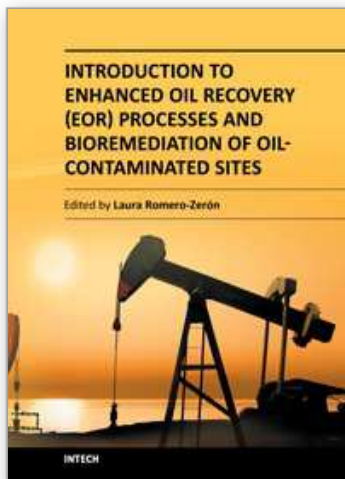
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Introduction to Enhanced Oil Recovery (EOR) Processes and Bioremediation of Oil-Contaminated Sites

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This book offers practical concepts of EOR processes and summarizes the fundamentals of bioremediation of oil-contaminated sites. The first section presents a simplified description of EOR processes to boost the recovery of oil or to displace and produce the significant amounts of oil left behind in the reservoir during or after the course of any primary and secondary recovery process; it highlights the emerging EOR technological trends and the areas that need research and development; while the second section focuses on the use of biotechnology to remediate the inevitable environmental footprint of crude oil production; such is the case of accidental oil spills in marine, river, and land environments. The readers will gain useful and practical insights in these fields.

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