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Public abstract

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme[1]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

This document summarizes the approach that will be taken in the case of breach of the caprock, typically along a fault or a fracture zone. Here, we consider two methods: 1) methods using polymer based gels and 2) methods using foams or gel-foams.
The oil and gas industry has long-term experience in reducing the flow rate of a given fluid, or maximizing oil or gas recovery by injecting viscous fluids or foams with specific properties. The objective is to select or adapt such techniques for reducing or stopping the migration of CO_2 through faults and fractures.

In general, two potential leakage pathways will be considered: (i) Leakage through an areal sink, represented by a fracture zone in the caprock, (ii) Leakage through a line sink, represented by a fault extending through the caprock into the overlying formation. Polymer-gels are expected to be injected at the top of the caprock using a permeable layer. Foams or gel-foams are expected to be injected below the caprock at the top of the storage zone.

Laboratory work will be performed to define the best formulations and performances of polymers and foams. This work will be complemented by numerical simulations to study essentially the radius of effective intervention.

[1] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

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1 INTRODUCTION

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 programme[2]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

This document summarizes the approach that will be taken in the case of breach of the caprock, typically along a fault or a fracture zone. We consider two methods: 1) methods using polymer based gels and 2) methods using foams or gel-foams.

Describing in some details the planned work performed by several teams from different institutions is an important step to insure a coherent and complementary approach at the beginning of the project, both in the laboratory and for numerical simulations. Hence, this document constitutes an important reference to guide the research efforts for the next two years.

For both methods, a brief state-of-the-art review is provided, essentially with publications originating from the oil and gas literature. For CO_2 applications, we can indeed benefit from a large knowledge from the Oil&Gas industry in which these techniques are used for many purposes. Then the scenarios envisaged are described, followed by a description of the models and/or the different steps for demonstrating the efficiency of these remediation methods, but also clearly stating their limitations.

[2] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

2 METHODS USING POLYMERS

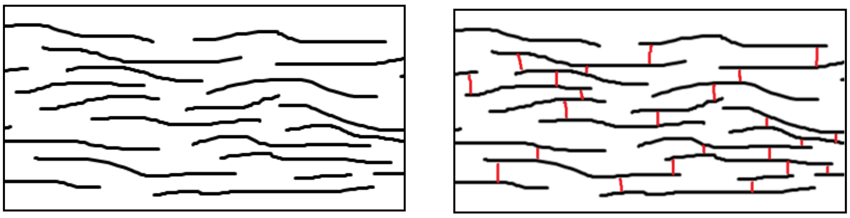
The oil and gas industry has long-term experience in reducing the flow rate of a given fluid, or maximizing oil or gas recovery by injecting viscous fluids or other fluids with specific properties. The objective of WP6 in the MiReCOL project is to select or adapt such techniques for reducing or stopping the migration of CO_2 through faults and fractures. Work includes the validation of a method in the laboratory, and the description of the possible range of action when injecting the sealant from a well. The latter is performed by numerical simulations. The possibility of accessing an out of range leaky location by hydraulic fracturing will also be considered.

2.1 Background and review of the state of the art in the use of gels in industry

Crosslinked hydrolysed polymer-gel injection is used in petroleum industry to improve conformity of fluid flow in the reservoir, remediate leakage around wells and also used in conjunction with the prospect of enhanced oil recovery under various temperature and pressure conditions[1,2,3,4,5,6,7,8,9,10,11,12,13,14,15,16,17] and to improve miscible CO_2 floods[18, 19].

The majority of field practice in applying gel treatments aimed to reduce channeling in high-pressure gas floods and to reduce water production from gas wells[20,21,22,23]. Often referred to as relative permeability modification (RPM) or disproportionate permeability reduction (DPR) and water shut off (WSO) treatments, there are many examples of production performance modeling data for gel treated wells in the literature[24,25]. In the early days of the technology, RPM treatment was mainly used in controlling flow in matrix-rock porous media. More recent research have reported successful treatment of fractured rock where relatively strong gels impart RPM/DPR to fluid flow within gel filled fractures and achieve total shutoff[13].

Hydrolysed polyacrylamide (Figure 2-1a), in various proportions, is one of the widely used polymers within the petroleum industry[26,27]. The polymer exists as loose molecular chains in the aqueous solution. When appropriate crosslinker is added, these polymer chains are aligned and this polymer solution is turned into a solid gel which resembles the structure illustrated in Figure 1b. Metal ions such as Cr^{3+}[28,29,30,31] and Aluminum[32,33] are widely used as a crosslinkers, although occasional use of organic crosslinkers such as formaldehyde[34] was also observed. Polyacrylamide based-gel solutions are used in the industry to selectively shut off undesired gas influx in production fields[35,12,36,37] and sometimes in combination with other surfactants[38]. Application of polyacrylamide-gel solution for modifying injectant flow profile are also noted[39] in addition to remediating non conformal flow within the reservoir[40].



(a) (b)

Figure 2-1: (a) Artistic representation of polymer chains in carrier fluid and (b) effect of crosslinker on the arrangement of polymer molecules in the solution.

The rheological characteristics of polymers injected into the subsurface reservoir are modified in time either by adding an additive, or just by interaction with the environment such as variation in temperature, pressure or surrounding fluids. These changes are observed to be accomplished either through the injection of individual components ie., monomer, cross linker and other additives or through injection of crosslinked polymer directly into the reservoir[41].

The time taken for hydrolysed polymer to be converted into polymer gel upon the addition of cross linker is generally termed as gelation time, which is also an indicator of the possible penetration of the injected polymer gel solution into the reservoir before it solidifies. Gelation time is also defined as the time when the elastic and viscous moduli of the gel are equal[42]. This time is dependent on the characteristics such as chemical composition, molecular weight and concentration of the polymer, temperature and cross-linker type. Hence, the temperature and salinity of the reservoir are important factors in the selection of appropriate concentration of a polymer and the cross-linker. Addition of organic ligands and pre formed Cr^{3+} complexes with suitable ligands added to the polymer solution were found to control the gelation time over the temperature range of 60-135^{o}C[43]. Furthermore, aqueous solution of dilute polyacrylamide was reported to be reasonably stable under shear. The stability of a polymer-gel system was reported to be dependent on the stability of polymer molecules themselves[44,45] .

Preliminary laboratory characterisation and assessment for field application of one polyacrylamide based polymer gel system was carried out as part of the EU funded CO2CARE project. The important conclusions of the work are summarised here:

1. The gelation time decreases with increase in polyacrylamide concentration; furthermore, for identical combination of polyacrylamide and Cr^{3+}, the gelation time was found to decrease with increase in temperature.
2. CO_2 permeability reduction of more than 99% can be achieved in high permeability sandstones
3. An increase in irreducible brine salinity generally leads to the destruction of the polymer chains and a notable reduction in permeability. However, almost 90% reduction in permeability was still achieved in higher salinity environments (12 to 25%).
4. Water slug experiments in the laboratory have confirmed that the negative impact of high salinity on permeability reduction in aquifers can be reduced by this technique.

In summary, high molecular weight, anionic and hydrolised polymer chains such as poly acrylamide along with a cross linker can be used to remediate leakage of CO_2 if the area of influence is carefully evaluated and the injection process designed accordingly.

The design of an efficient remediation strategy using polymer gel for possible CO_2 leakage would depend on engineering the gelation time of the polymer and crosslinker combination for the targeted subsurface reservoir conditions, which would be investigated though the current research.

2.2 Envisaged scenarios

Two storage models will be used in the study: the Imperial College Saline Aquifer Model (ICSAM) model and another model representing a typical reservoir containing a fault, here named Px model. In general, two leakage pathways will be considered:

- Leakage through an areal sink, represented by a fracture zone in the caprock
- Leakage through a line sink, represented by a fault extending through the caprock into the overlying formation

The polymer gel is intended to be injected in one permeable layer in the overlying structure above the caprock.

Previous research has shown that gelation time and effectiveness of polymers depend on temperature, pressure and salinity of the reservoir fluid. Therefore, for each leakage pathway, the following key features will be considered and implemented to form a number of modelling scenarios:

- Storage reservoir depth (formation pressure and temperature)
- Caprock thickness/distance to the permeable layer above the storage reservoir
- Permeable layer permeability/porosity
- Permeable layer brine salinity

Polymer gel injection scenarios will investigate the effectiveness of the selected polymers in terms of:

- Radius of effective intervention for different polymer types and concentrations
- Composition of the leaked CO_2 plume and CO_2 mobility with and without polymer-gel remediation

In leakage scenario simulations, the amount of CO_2 leaked out of the target storage reservoir at a selected location is continuously monitored, and the injection is terminated once a pre-set detection threshold is exceeded. The leakage, however, is allowed to continue until its source (the free CO_2 in the storage reservoir available for leakage) is exhausted to yield the total leakage potential. In this way, potential leakage risk profiles through the leaky caprock/faults may be established to provide a benchmark for evaluating the effectiveness of any remediation measure.

In a study of a depleted gas field, several CO_2 migration scenarios have already been studied by Vandeweijer et al.[46], to determine the risk of migration of CO_2 through the overburden. In particular three migration paths had been taken into account: through the aquifer reservoir spill point, through an induced fracture into the primary seal with a migration of CO_2 into the overlying sandstone and, finally, through a wellbore shortcut. For these migration analysis a Petrel model of the overburden was constructed. Vandeweijer et al.[46] concluded that for the depleted gas field studied the most plausible migration pathway of the stored CO_2 to the surface was via leaking wells; a pathway that developed within the overburden was considered highly unlikely.

Following the results presented by Vandeweijer et al.[46], we have constructed a model of reservoir plus cap rock structure and geology that is best suited to simulate the case of CO_2 leakage through existing faults, using induced hydro-fractures to transport the sealant to the leaking location.

2.3 Numerical modeling of gel remediation

The main requirement of the reservoir model(s) are: inclusion of a caprock and the presence of at least one permeable layer in the overlying structure above the caprock where polymer solutions can be injected. The second requirement is the presence of migration pathways through the caprock, in the form of fracture zones or faults.

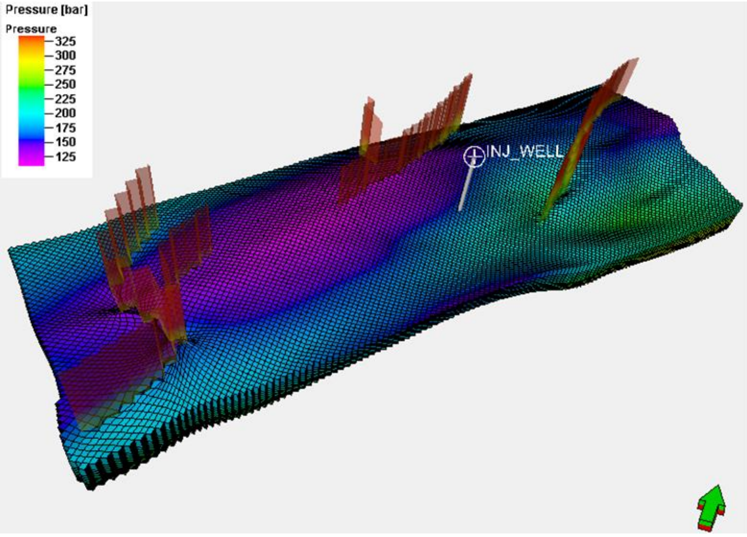
2.3.1 ICSAM Model

Leakage through an areal sink represented by a fracture zone in the caprock

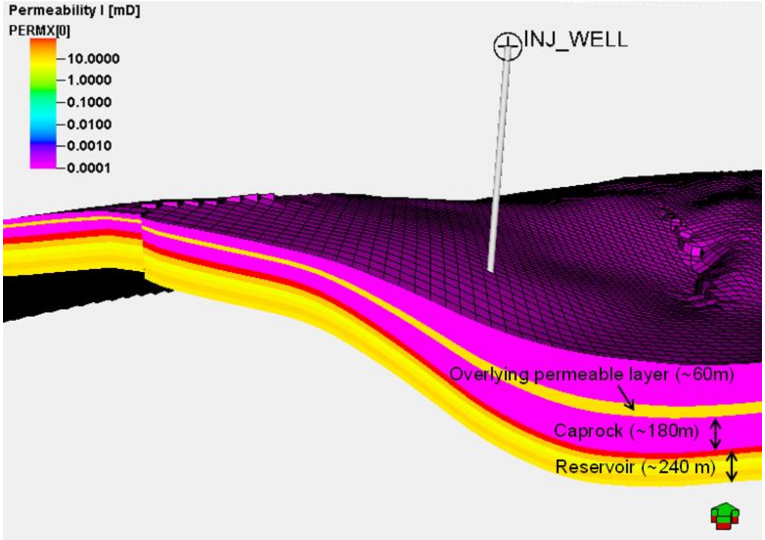
Guided by the above model requirements, the Imperial College Saline Aquifer Model (ICSAM) developed in CO2CARE project has been chosen as the base model to carry out the polymer injection scenarios for the areal sink case.

The ICSAM model measures 36 km x 10 km and includes several faults (Figure 1a). The depth of target storage formation ranges from 1,082 to 3,484 m across the model domain, dipping considerably. The injection well is located at a location where the storage reservoir is between 1,973 to 2,181 m deep (Figure 2-2a). The model has a more or less uniform grid block size of 200 m x 200 m in the lateral direction.

The storage reservoir, which has a thickness of approximately 240 m, consists of 6 layers of varying properties both within each layer and across the layers. The overlying formation (caprock) is considered to be impermeable, except for a 60 m thick layer situated at 180 m above the reservoir, which is assigned a permeability of 10 mD (Figure 2-2b). The reservoir/overburden is initially at hydrostatic pressure, and the reservoir temperature is 92 ^{o}C.



(a) Hydrostatic pressure distribution



(b) A close-up showing the caprock and overburden layers.

Figure 2-2: Imperial College Saline Aquifer Model (ICSAM).

2.3.2 Notional storage model

There are already many different mitigation and remediation technologies to apply in case of unwanted migration of CO_2 from CO_2 geological storage units. Some of them have already been used in real cases, while others only in laboratory tests. An interesting overview of these different techniques can be found in Manceau et al.[47] (2014). The characteristics, the viscous, mechanical and chemical properties of polymer gels match perfectly the needs of a method to mitigate leakages. Our idea is to create and use hydro-fractures to transport the sealant gel to the leaky fault to mitigate or remediate the CO_2 leakage. Another interesting option would be to stimulate a horizontal hydro-fracture to create a sort of blanket that act like an impermeable barrier (see Figure 3). This would be possible only for shallow reservoirs in which the vertical stresses horizontal fractures to be formed.

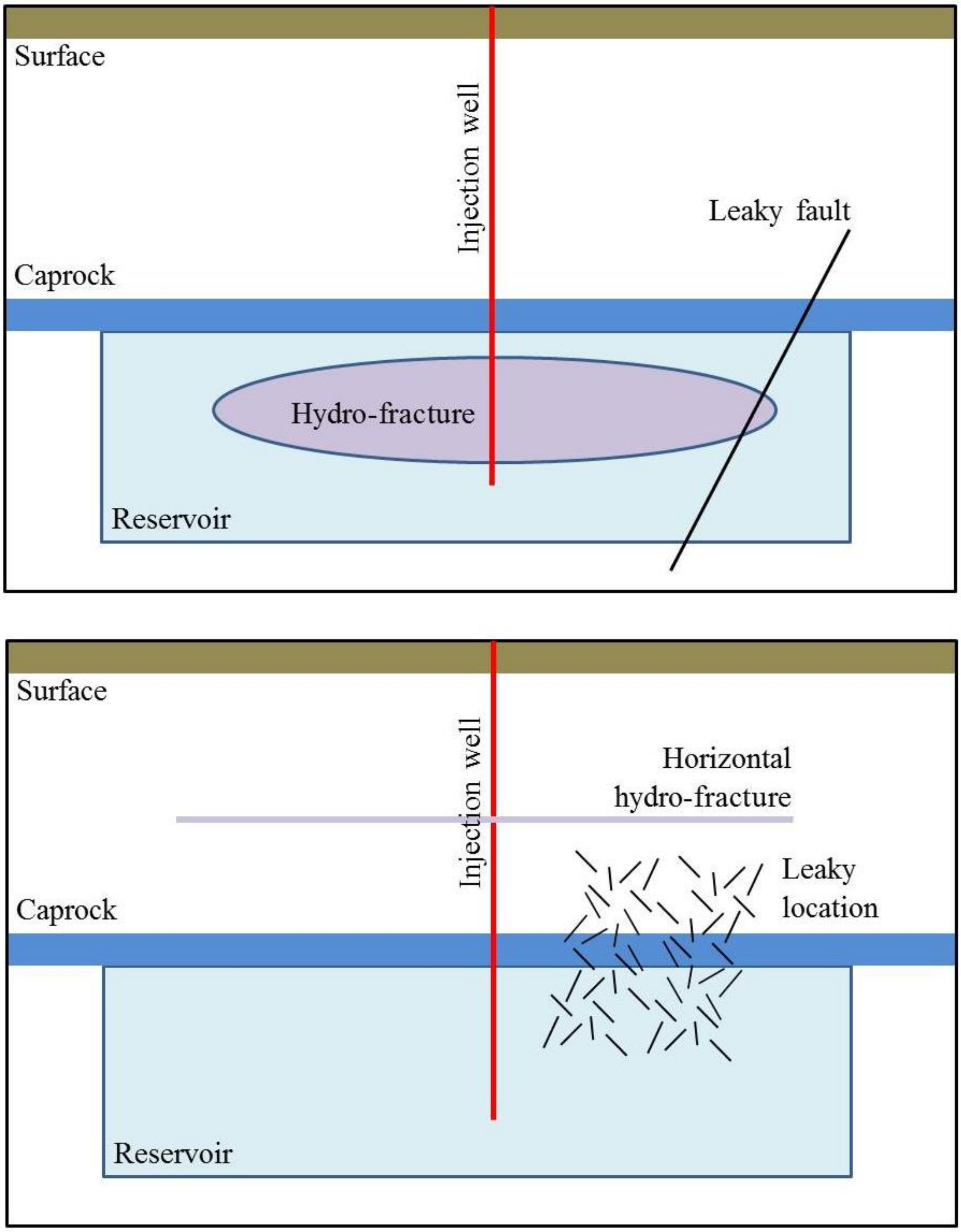


Figure 2-3: Schematic representation of the methods.

We will perform the numerical simulations with the software MFRAC. After creating the 1D geomechanical model, such as shown in Figure 2-3, we will import the 1D model into the software and we will try different kind of injection rates and replace the proppant by polymer based gels. Playing with different viscosity, mechanical and chemical properties of the gel and with different injection rate of the fluid, we want to study how far, how well and how accurate we can transport the sealant to a leaky location. The aim of this work is to define which parameters control the effectiveness of the two methods that we proposed, to allow operators to use these solutions also for other fields.

2.4 Summary

The injection of polymer gel will be studied, with the objective of reducing CO_2 leakage through the caprock. Two leakage situations are considered:

- Leakage through an areal sink, represented by a fracture zone in the caprock
- Leakage through a line sink, represented by a fault extending through the caprock in to the overlying formation

The required characteristics of the polymer gel will be studied in the laboratory: gelation time, crosslinker combination for the targeted subsurface reservoir conditions. The large experience gained in the oil and gas industry will be used for the choice of the best adapted polymers.

Large scale numerical modeling will be performed to study the effectiveness of the method. For this purpose, two models will be used: a saline aquifer model (ICSAM) and a model of a notional storage site that includes reservoir, cap rock and overburden.

3 METHODS USING FOAMS

Foams have been used in Enhanced Oil Recovery (EOR) as the most promising and cost effective means to alleviate the drawbacks associated with gas-based EOR processes such as viscous fingering, channelling, gravity override and early gas breakthrough. Indeed, generation of strong foams could drastically reduce gas mobility improving volumetric sweep efficiency.

Foams can be used for in-depth gas mobility control, as blocking agents (thief zones, Gas-oil-Ratio reduction) and conformance control (fractures, large permeability contrast, and layered reservoirs). Thus, besides their use for EOR purposes, they can be also used to secure gas storage operations through gas confinement and gas leakage prevention/remediation. Indeed, one can increase considerably the apparent viscosity by injecting water with a foaming agent. In this situation, the simultaneous flow of gas and water will generate a foam depending on certain conditions. The onset of a foam depends primarily on the gas to liquid velocity ratio, and also on the choice of surfactant quality and concentration.

We propose to study in the laboratory the conditions of generation of a CO_2-brine foam in a fracture and to study using numerical simulations the conditions for accessing the bottom of the fracture in the caprock.

3.1 State of the art

Although a significant volume of theoretical, laboratory and pilot work has been dedicated to foam processes[48,49,50,51,52,53,54,55,57,58], it is still a developing technology and significant uncertainties still remain regarding the actual physics underlying foam generation/ propagation in porous media. The main challenges are to bring this promising technology to the field and to perform field trials and pilots. This requires being able to probe the feasibility and predict the effectiveness and the added value of this method compared to other means to justify the associated investments and risks. In turn, this requires an effective synergy between simulations and experimental work in order to convert laboratory data to reliable field scale predictions.

Regarding CO_2 storage operations, gas confinement is of outmost importance to ensure that such process can be used as a safe and effective solution for greenhouse mitigation. A clear insight on the associated risks, their sound evaluation and the development of means for their prevention and mitigation are thus needed. Among these risks, CO_2 leakage through/along wells, faults and fractures and through the sealing cap-rock are the most important to consider. Indeed, due its low density and high mobility, gas might potentially migrate out of the storage zone towards the upper formation due to gravity segregation and finally might leak into the atmosphere. This leakage potential is mainly dependent on well and sealing cap rock integrity.

Due to their ability to preferentially restrict fluid flow in the most permeable areas, foams are particularly indicated to address the leakage from high-permeability areas or through fracture and fissures that are considered as the most important leakage pathways[59].

3.1.1 Brief on foam description and use

As mentioned above, foams could be used for different purposes including gas mobility control, conformance improvement and as blocking agents. For each application, specifically designed foam systems should be designed to meet the application requirement under controllable conditions. For in depth gas mobility control for example, a "weak foam system" providing moderate gas mobility reduction is preferable as it requires to be propagated deeply inside the reservoir. In turns, "strong foam system" opposing high resistance to fluid flow up to its complete plugging is required for conformance improvement and blocking purposes of specific areas.

3.1.1.1 General aspects

A foam system classically consists of water continuous phase and dispersed gas (bubbles) at a given volumetric fraction usually termed foam quality. Gas bubble formation requires a certain amount of energy (shear) and are stabilized by foaming agents (surfactant) that are classically dissolved in the water phase (but could be also in the gas phase: CO_2).

The characterization of foam in bulk solution is usually based on several properties such as[60]:

- Foam quality or the volumetric gas fraction. Foam with large foam quality (that can be as large as 97%) are referred to as dry foams while wet foams are those with low foam quality. There exists an upper foam quality limit above which foam collapse (dry out effect). For EOR , usual foam quality are between 70 and 90%.
- Foam texture that refers to gas bubble size. At the same foam quality, more finely "textured" foam contains a larger number of bubbles and lamellae (see section 3.1.1.2).
- Bubble size distribution
- Stability that is usually quantified by the foam half-life parameter that measures the time for a column of foam to decrease to the half of its initial height.

 Among these properties, the stability is of utmost importance for foam application. Foams are dispersed systems and, as such, they are intrinsically unstable with time. However, for gas mobility control in EOR, foam should be stable and propagate inside the reservoir and for conformance and blocking purposes, they should remain stable in place for a given time that ensure the economic viability of the process (frequent treatment could be detrimental to the economics).

The stability of foam is mainly dependent on the chemical and physical nature of the surfactant (or surfactant formulation) used as foaming agent, but of course also on the system nature (gas, brine and oil for EOR operation) and application conditions (P, T and formation properties: mineralogy, permeability, etc.).

Finally, foam usually has a low density compared to the liquids present in the injection formation. Several applications (gas coning prevention and GOR reduction, injection of low interfacial-tension formulation in the gas cap) take advantage from this property for foam emplacement in the targeted upper part of the reservoir.

3.1.1.2 Foam behavior in porous media

Foam generation and transport in porous media result from a dynamic equilibrium between lamellae creation and destruction. This equilibrium determines foam texture in porous media, that is usually different from that in bulk solution, and which, in turn, governs to the flow behavior (finely textured foams with a large number of lamellae are expected to induce higher resistance to flow). Foam stability equilibrium could be impacted by a huge number of parameters including reservoir properties (rock type, K, heterogeneity, wettability, P, T), fluid properties: oil/gas/brine (compositions, density and saturations), surfactant properties (nature and concentration) but also fluid/fluid and fluid/rock interactions (adsorption, solubility/partition, dissolution). Foam destabilization could result from several effects including excessive film thinning and rupture, diffusion of gas from smaller bubbles into the larger bubbles (coarsening or Ostwald effect), lack of surfactant because of excessive adsorption on the surface of reservoir rock or precipitation due to adverse brine salinity and hardness, high capillary pressure and presence of oil[61].

Currently, large uncertainties and incompletely understood areas still remain regarding the actual physics underlying foam flow in porous media. Though the previous studies[49,50,51,52,53,54] did not allow to propose a comprehensive and satisfactory physical modeling of foam flow and propagation, they allowed to come up with a general, yet useful, phenomenological description of the rheological behavior of foams in porous media:

a. Foam generation and stability

- Lamellae creation results from different mechanisms such as leave-behind, snap-off and lamellae division[52] (see Figure 3-1)..

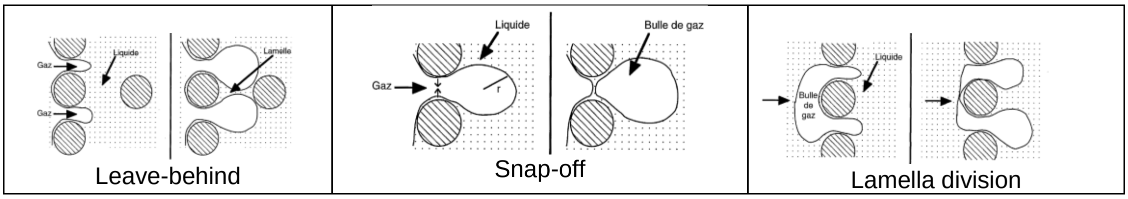


Figure 3-1: main lamellae generation mechanisms

- Lamellae destruction and film rupture result mainly from: capillary pressure (when $Pc=Pc^{*}= P_d^r$, critical disjoining pressure)[55], oil impact if present (nature and saturation: existence of a critical saturation)[61,62], very low water saturation (below a critical value S_{wmin}), insufficient or excess shear and from gas trapping (depending on fluid saturation, pressure gradient and pore structure).

- Two categories of foams are usually distinguished: "weak foams" and "strong foams". The transition between the two types of foam is often abrupt and requires a minimum pressure gradient $\triangle Pc$[49] or a minimum critical velocity Vc[49]. Weak or coarse foams induce only low resistance to flow (low gas mobility reduction factor, or MRF) while strong foam leads to much larger resistance to flow (with non-dense gas like N_2 the induced MRF can reach values greater than 1000). For CO_2, the mobility reduction factor is usually much lower and the maximum attainable value decreases rapidly with CO_2 density[63,64,65]. With supercritical dense CO_2 it was inferred from laboratory study, using classical foaming agent, that probably only coarse foams-emulsions could be formed. However, more recent results[62] showed that, even with dense-CO_2 and using dedicated surfactant formulations, gas mobility reduction factors as high as 25 could be obtained indicating the formation of strong foams.

b. Foam flow: rheology and transport

- In porous media, foams consist mainly in "bubble trains" that increase gas viscosity/ decrease gas mobility.

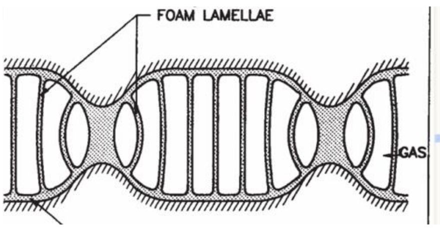


Figure 3-2: bubble trains in a pore

- The resistance to gas flow is usually evaluated using the gas MRF calculated as:

$$MRF=\Delta P_{Foam}/\Delta P_{no\ Foam} \quad (1)$$

  - MRF determined by the resistance of the lamella to coalescence
  - Apparent foam viscosity is due to pressure required to displace bubbles:
    - Continuous gas foam causes high mobility or low apparent viscosity
    - Discontinuous gas foam causes low mobility or high apparent viscosity

$$\mu_{app} = \frac{Krw.\Delta P}{Vint.\phi.L} \quad (2)$$

where μ_{app}: apparent foam viscosity; Krw: effective brine permeability at residual oil saturation; Vint: interstitial velocity (= $Q/S\phi$); ϕ, L: porosity and core length

- Strong foam flow exhibits two flow regimes depending on foam quality fg [fg= $q_g/(q_g+q_w)$] (high quality regime and low quality regime). The transition occurs at an optimal foam quality fg* corresponding to the critical capillary pressure

Pc* and to the maximum in pressure drop. Below fg* (wet foam with low quality), the pressure drop is almost independent of liquid flow rate and above fg*(dry foam with high quality) it becomes almost independent of gas flow rate (Figure 3-3)[56,66].

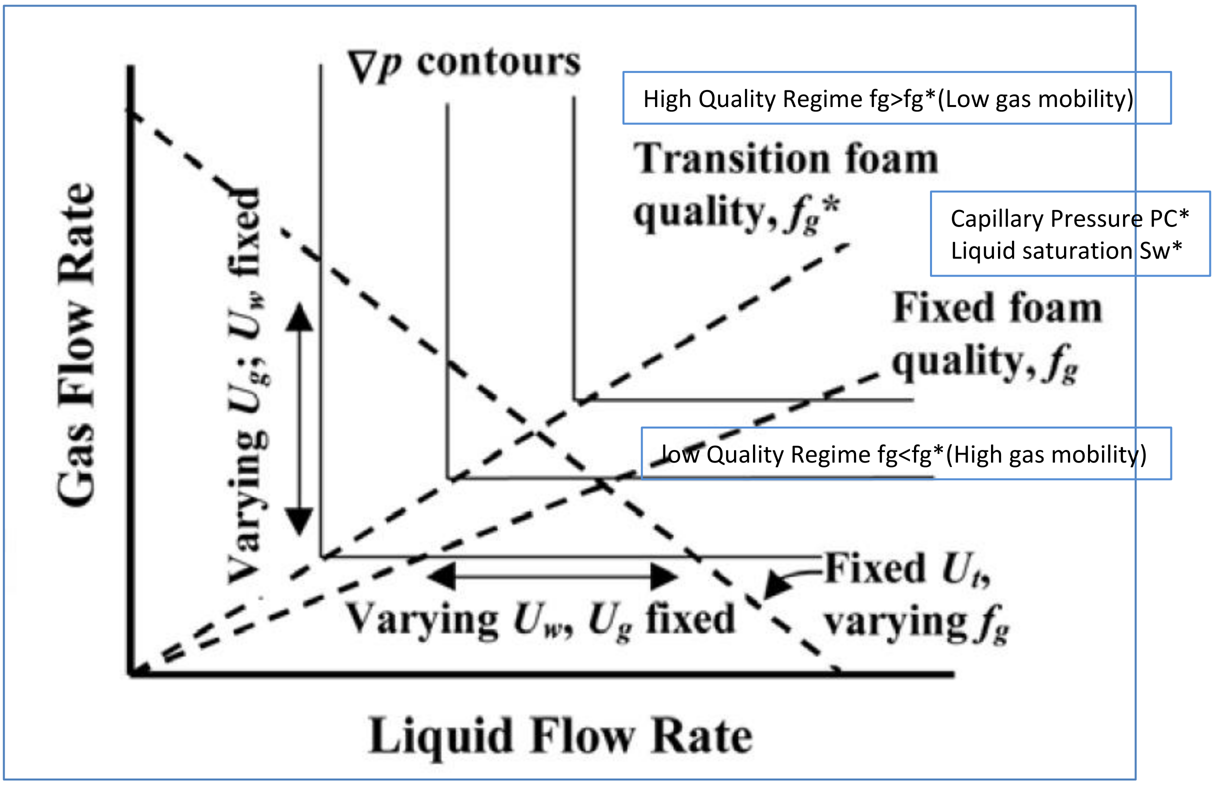


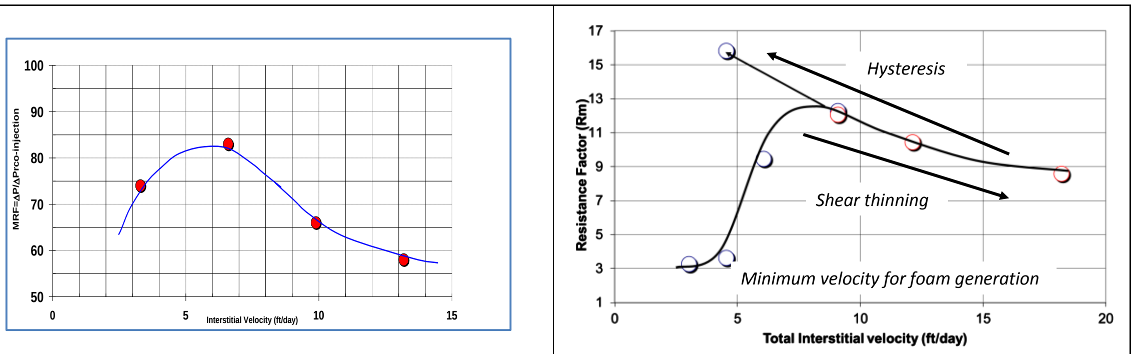
Figure 3-3: The two flow regimes for strong foams[56]

Thus, according to this view, the foam-induced pressure drop usually exhibits a maximum when plotted against foam quality[56,63,67,68]. This maximum is reached at the optimal foam quality fg* that depends on system characteristics and especially on formation permeability, surfactant and flow rate. This optimal foam quality is a very important parameter to determine for a given application case. It has been demonstrated that for strong foam generation, a minimum pressure gradient or a minimum critical velocity is required[49]. Once these strong foams are generated inside the porous media, their rheological behavior shows the following main trends:

- First, MRF increases with increasing velocity up to a maximum.
- Then, MRF decreases upon further increasing the velocity beyond the maximum (shear thinning behaviour).
- Finally, MRF shows an hysteresis effect when the velocity is decreased.

Most of the foams exhibit the shear thinning behavior. This is an important advantage for the use of foams in EOR for sweep improvement. Indeed, foams are usually generated in situ in the near wellbore area where the velocity is high, leading to low

MRF that mitigate the injectivity issue. Far way from wellbore, the velocity decreases leading to higher MRF with better sweep efficiency.
Such typical rheological l behavior is illustrated on Figure 3-4.



Non-dense gas (C02+ CH4) 100°C, 100b

Dense CO2 , 40°C, 130b,

Figure 3-4: Typical foam rheological behavior (IFPEN results).

c. Foam flow modelling

Several approaches have been proposed to model foam flow in porous media. These include empirical, semi-analytical and mechanistic approaches. Mechanistic approaches are based on the dynamic mechanisms of lamella generation/destruction and make use of population balance equation for bubbles[48,69,70,71,72,73,74,75]. They attempt to take into account the space-time variation of foam structure/properties and their relation to rheology. These models use conservation and rate equations for bubbles and take into account trapped gas. The use of such comprehensive models is however limited due to the number of parameters that are difficult to obtain, measure and scale-up at larger scale. The semi-analytical approach is based on the application of fractional flow theory of Buckley/Leverett to foam flow[76,77]. This approach has of course the limitation of the fractional flow theory. Though this type of model is able to reproduce the general foam behavior described above, its use for foam is limited due to the assumptions used. Therefore, in the absence of a comprehensive, simple, yet useful, physical modeling of foam flow in porous media, only the empirical approach is currently used in most of the reservoir simulators. Within this approach, based on the local steady-state model, the effect of foam on gas mobility is modeled through a simple modification (parameterization) of the relative gas permeability in presence of foam using a functional form FM

$$[K_{rg}^{foam}(S_g) = FM.K_{rg}^{no\text{-}foam}(S_g)] \quad (3)$$

Thus, the functional form FM controls the gas mobility reduction in presence of foams and is written as follows[78]:

$$FM = \frac{1}{1+(Mref-1)\times F1 \times F2 \times F3 \ldots Fn} \quad (4)$$

The functions Fi ($0 \leq Fi \leq 1$) take into account the contribution of the main parameters impacting the gas mobility. If all the Fi's are set to unity, then FM= Mref. Mref is the

maximum gas mobility reduction factor that could be obtained from the gas MRF obtained from laboratory experiments (see eq. (1)).
For example, if we consider only the impact of surfactant concentration (F1), water saturation (F2), capillary number (F3) and oil saturation (F4), FM becomes:

$$FM = \frac{1}{1+(M_{ref}-1)\times F_1 \times F_2 \times F_3 \times F_4} \tag{5}$$

Such an empirical model has no predictive abilities and needs to be calibrated (Fi determination) for each application case before its use[66]. It cannot describe the variability in foam properties with time and space inside the reservoir as it does not include any actual physics of foam process.
Simulation at pilot and field scale of foam process is a perquisite to convert laboratory data into field predictions, as well as for foam process optimization. Such optimization includes:

- Injection strategy to maximize oil production and/or for a proper emplacement and a clear identification of the targeted area for conformance and blocking purposes.
- To optimize the volume to be injected which is of the utmost importance for the economics of the process.

d. Foam use

Foams have been widely used during EOR operations both for conformance improvement and in-depth gas mobility control, with varying success. The main successes were for conformance purposes while disappointing results were obtained for in-depth gas mobility control. A detailed literature review, including pilot trial analysis, is available in the literature[53,87].

Foams have also been tested, both at laboratory and pilot scale, as blocking agents mainly for GOR reduction through gas coning limitation[79,80,81,82,83]. For underground gas storage, the use of foams to improve and secure these operations has been investigated by several authors[84,85,86]. The objective of using foam in these operations is to prevent gas leakage or the increase the storage volume. Foam could also be used to block water flow or to modify gas mobility. The use of foam for gas leak remediation during gas storage operations could greatly benefit from the experience gained from the use of foams as blocking agent in the oil industry, especially for conformance issue remediation and GOR reduction through gas coning limitation from the gas cap.

For the use of foams as gas flow blocking agents, the foam emplacement and its resistance to gas flow as well as its durability and stability are of the utmost importance for the efficiency and economics of the process. Though the use of “classical” foams for controlling excessive GOR has been considered as a promising technology[81,83,88,89], it was shown that these foams have limited lifetime (weeks to months) and the treatment often needs to be repeated[89]. Cubillos et al. showed that stable foams are formed in a sand pack plug with alkyl olefin sulfonate (AOS C14-16) by injecting gas at 2 m/d behind a surfactant slug. The pressure drop reached was about 35 bar with an estimated mean value of MRF of about 100. However, when the gas rate was increased to 4 m/d, a rapid foam decay was observed with a decrease of MRF by a factor of about four after 20 PV were injected (the pressure drop fell from 35 bar to only 8 bar over six days). Thus, the classical foams:

- are unlikely to completely block gas flow,
- provide only limited durability and stability with time,
- do not induce residual permeability reduction after foam decay.

These aspects are even more crucial in the case of the use of CO_2-foams for gas leakage prevention/remediation during CO_2 storage operations. Indeed, compared to other foam systems like N2-foams or natural gas-foams, CO_2-foamss usually generate much lower MRF due to the impact of CO_2 on the interfacial tension[49,62,63,64,65]. In addition, the CO_2-foam-induced MRF are very sensitive to the CO_2 density and thus to injection and reservoir conditions of pressure and temperature[65]. Solbakken et al.[65] studied the impact of CO_2 density on MRF using AOS-based foaming agents and found that the MRF is strongly affected by the supercritical CO_2 ($scCO_2$) density, with MRF values of about 55 at a density of around 0,2 g/cm^3 and less that 5 at a density of 0,85 g/cm^3, the latter value indicating the presence of only coarse foam. Chabert et al[62] infered from a laboratory study that $scCO_2$-dedicated surfactant could improve $scCO_2$-foam resistance to flow and showed that MRF as high as 23 could be reached even with high CO_2 density. However, even such MRF are not high enough to block gas flow and to consider CO_2-foams as a promising method for gas leak blockage.

Alternatively, several improvements have been proposed with the objective of increasing the foam system strength, its resistance to gas flow and its durability once emplaced in the targeted area. This includes mainly polymer enhanced foams (PEF) and gel foams[89,90,91,92]. From these previous studies, gel-foam appeared to be the more promising technology for gas flow blockage, but it requires a careful design together with an optimization of the strategy of injection and emplacement. This, in turn, requires a tight synergy between laboratory experiment for the design and testing and simulation for the process optimization.

3.1.2 Brief on gel foams

a. Gel foam: what is about?

Gel foams consist in forming foams by creating and stabilizing gas bubbles in a liquid solution that is able to undergo gelation. Foam is formed and stabilized using a foaming agent (surfactant). The liquid solution usually consists of a solution of high molecular weight polymer with reactive ends (ionic groups for example) distributed along the molecular chains. Gelation is provoked by incorporating in the polymer solution a specific crosslinker that is able to react with the polymer reactive ends to form intermolecular bridges and polymer gel. Initiation of this gelation reaction is usually controlled using a delaying chemical agent (ligand) that is also incorporated in the polymer solution at the desired dosage. Thus, a gel-foam formulation (liquid solution) usually contains:

- A polymer with reactive ends along the molecular chains,
- A crosslinker,

- A delaying ligand, and
- A surfactant (foaming agent).

This liquid solution is, of course, to be customized (formulated and optimized) for the targeted application to reach the desired objectives.

b. Gel foam: what is it for?

For EOR and well productivity improvement gel-foams are used as blocking agent to prevent fluid flow (gas or water) into or out of an undesired area. Thus, gel-foam could be used to block thief zones, for conformance control in fractured/layered reservoir or in presence of high permeability contrast. One of their most interesting and promising applications is to increase well productivity through GOR reduction by blocking gas influx. Similarly, they could be used also for confinement purposes to prevent CO_2 leak across the cap-rock in a CO_2 storage reservoir. Taking advantage from their low density, gel foams could be placed toward a gas gap for gas coning blocking or just beneath the cap rock as sealing agent of leakage zone through the cap rock.

However, gel-foam application is a very complex process that requires careful and thorough investigation and optimization to produce a customized, effective and safe solution for a given reservoir application. Two main issues should be mentioned here and are actually common to all the in-situ gelation processes: injectability of the delayed gel-foam that, actually is a PEF, and placement. Indeed, gelation is initiated in-situ once the non-gelled foam (PEF delayed foam) is placed in the area targeted to be blocked. Delayed gel-foams should be strong and stable in order to be propagated inside the reservoir and to form strong gel upon gelation initiation. Such strong delayed gel-foam, or PEF foams, should however exhibit acceptable injectability (to avoid exceeding reservoir fracturing pressure for example or to avoid excessive injection energy cost). The second issue is related to the emplacement and is more difficult. To take benefit from the process, it is a prerequisite to create gel only in the targeted area and to avoid blocking unwanted ones. Therefore, developing a customized gel-foam solution for a given application requires a good reservoir knowledge and careful and extensive optimization study as a function of product (polymer, surfactant, crosslinker, delaying agent) nature and concentration, injection conditions (flow rate, foam quality) and reservoir properties.

3.2 Scenario

The basic scenario is that injection of gel-foam takes place below the caprock from a well as close as possible to the leaky fault (Figure 3-5). Typically, the well is a rescue well rather than an existing one. Indeed, it is unlikely to drill a well close to a fault, unless such fault/fracture has not been detected initially. Due to a large density contrast, the gel-foam will migrate upward and reach the base of the caprock, where it can block the gas flow. The distance between the injector and the leaky fault is an important parameter that will be determined during the study. A key parameter for the propagation of the foam around the well is the adsorption of the surfactant on the rock mineral surface.

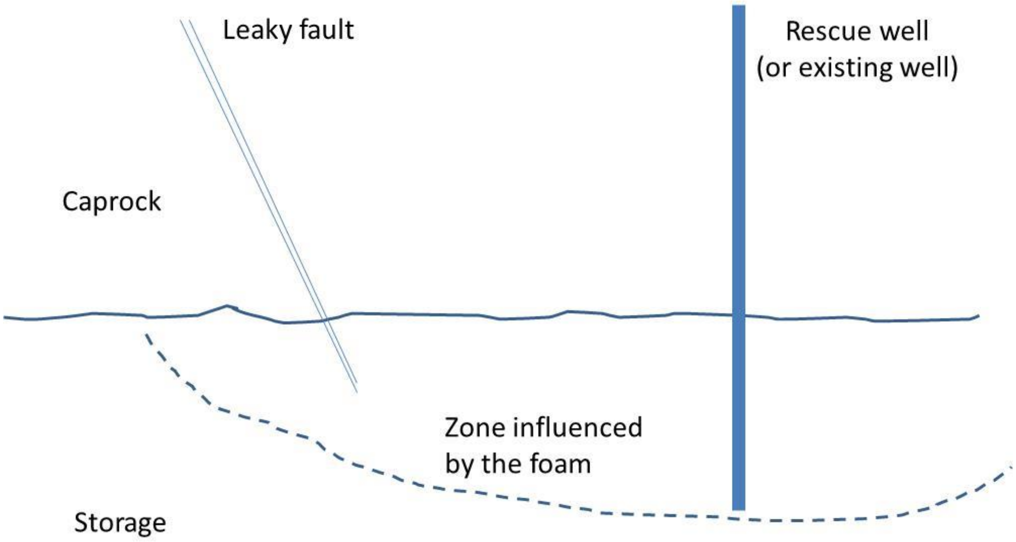


Figure 3-5: Schematic of the scenario envisaged for gel-foam remediation.

In the study of gel-foams, we will not consider a specific storage model due to the limited radius of influence that are inherent to these methods. For these reasons, it is sufficient to use generic models in which a layer of uniform porosity and permeability is implemented.

3.3 Study of gel-foam

As detailed above, the gel-foam technology appears to be a much better solution than foam alone for blocking fluid motions in a certain area. Although it combines two technical difficulties (foam and gelation), gel-foams have the essential advantage of a much longer stability if the gelation time can be tuned appropriately. The study of gel-foam contains two important steps:

- Part 1: Feasibility Study

  The objective of this first part is not to come up with a customized and optimized solution. It is a preliminary feasibility study to evaluate and check for the efficiency of gel-foam to block gas influx. It will consist of carrying out gel-foam system screening /design and petrophysics evaluations in core flooding tests in order to study the potential added value of gel foams as compared to classical and polymer enhanced foam.
  This preliminary part will consist mainly of the following tasks
- Screening and selection of the gel foam system based on bulk properties
    - Polymer selection: nature and concentration

  - Surfactant selection: nature and concentration
  - Crosslinker selection (based on gel strength determination): nature and concentration
  - Delaying ligands screening vs. gelation time
- Qualification and characterization in core floods
  - Characterization of the rheological behaviour in porous media of the polymer and polymer-enhanced foams
    - Brine, polymer, (polymer+CO_2), (polymer+surfactant+ gas) and finally gas
  - Characterization on the rheological behavior in porous media of the delayed gel-foam (with crosslinker)
    - Brine, polymer, (polymer+ gas), (polymer + surfactant + gas), (polymer+ surfactant + gas + crosslinker + delaying agent), gas (after shut-off and allowing gelation to occur)

At the end of injection sequences performed (PEF and gel-foams), the resistance ability of PEF or gel-foam to displacement with gas will be evaluated : the injection will be stopped and a low differential pressure will be first applied across the core (no gas at the outlet). The differential pressure will then and increased stepwise until gas breakthrough. Comparison of gas breakthrough onset differential pressure for PEF and Gel-foam will allow to evaluate the potential added value of gel-foam in the ability to block gas influx. Finally, the residual resistance factor to gas flow (gas injection) will be also determined.

- Part 2: Optimization study

One the feasibility has been demonstrated, the objective here is to optimize the solution including

- Gel strength,
- Delaying time (gelation kinetics),
- Propagation facility of PEF.
- Defining precisely the targeted area
- Injection strategy and emplacement
- Injection volumes

This optimization part will be carried out in close connection between formulation, petrophysics and simulation works.

3.4 Numerical modeling

The goal for the numerical modelling work is to assess the radius of intervention and placement of the different injected foams, gel foams or PEFs. Thus this work is not aimed at optimizing a site-specific (gel) foam injection, but to investigate the field scale behaviour for different realistic settings of an injected (gel-)foam.

Field scale simulation of (gel-)foam is necessarily limited to a more empirical approach. Such approaches are implemented in industry-standard simulators such as STARS[93], or

Eclipse or in dedicated applications such as those of the University of Texas (UTGEL[94,95]). These tools need to be calibrated based on field tests to make reliable predictions. However, for the current application, it is by definition impossible to perform such tests. In fact, the level of uncertainty is likely to be higher than for conventional oil reservoirs, especially for CO_2 storage in aquifers. Therefore the approach here is to investigate a range of effective properties of the (gel-)foam to be injected. The goal is to provide an overview of 'what if' scenarios: if a stable foam can be created with a viscosity reduction of x times the original viscosity of CO_2, how effective would that be? Also it will be investigated how robust the scenarios are and whether their robustness can be improved by for example injecting CO2 with a different temperature to improve placement of the foam.

Important aspects of the model work are:

- the effective properties of the created foam (viscosity, density, (relative) permeability reduction, adsorption (mainly of the surfactant)),
- geometry and position of the injection well (vertical, horizontal),
- geometry of the leakage area (fracture (line sink), areal sink),
- CO_2 leakage rate (to estimate the transport of the (gel-)foam into the fractures or fault),
- size and/or boundary conditions of the model (to estimate the pressure increase as a result of the injection).
- Possible dip of the caprock

To take the aspects listed above, a 3D model will need to be used with fine grids near the injection well and the fracture/fault.

The flow of the (gel-) foam in the leaking fault/fracture itself is not included in this part of the work, because it does not contribute to answering the question of the radius of influence.

Scenarios

As a real case for this part of the work package a model of a notional CO_2 storage formation has been chosen, which consists of a reservoir formation, a cap rock and a fault intersecting the cap rock. The model is the same as that used in study described in section 2.

Figure 3-6 gives an overview of the model setup. Both a horizontal and vertical injection well will be tested, because this well configuration strongly affects the potential radius of influence and the pressure increase around the injection well. The pressure increase should be limited as much as possible to avoid increasing the leakage problem. Of course, the choice of well also affects the pressure gradient and thus the creation of the foam, however that will not be taken into account since the actual process of foam creation is not simulated.

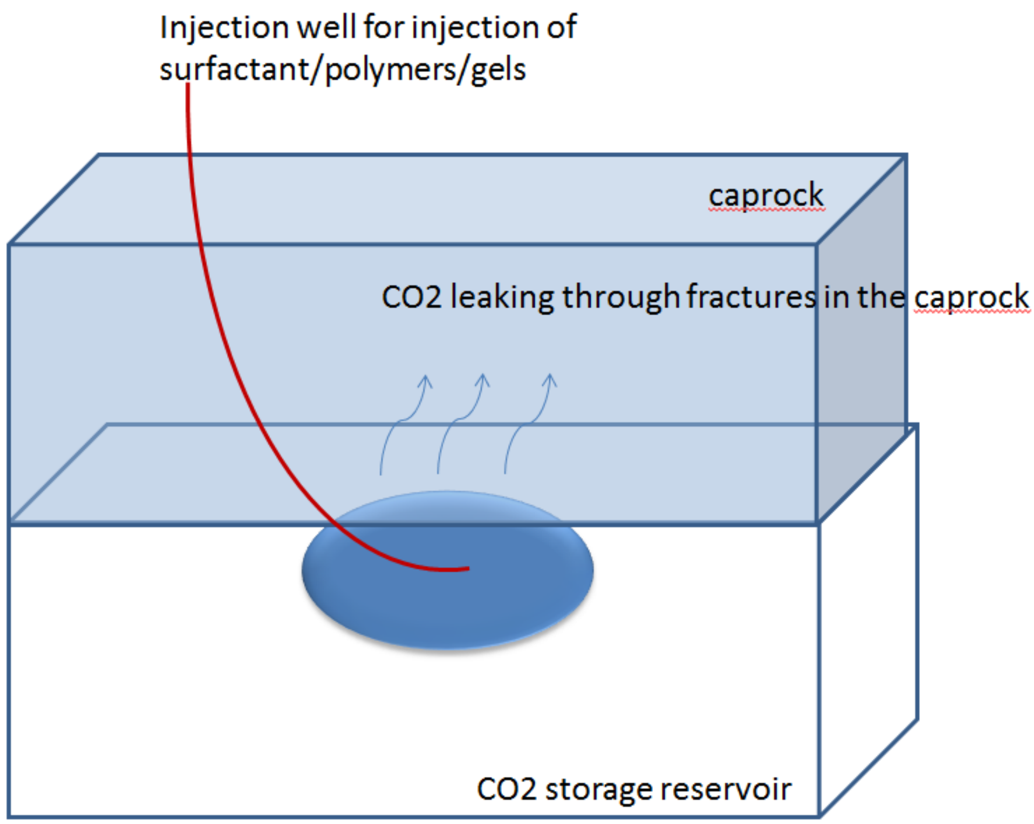


Figure 3-6: Setup of the model.

By not taking into account the fact that the gel-foam is formed inside the reservoir, the model might experience unrealistic injectivity problems. These can be alleviated by changing the relative permeability model of the well or by setting a negative skin. This should not affect the overall results much.

3.5 Summary

Foams have the ability to restrict or block the flow in high permeability zones. In the context of CO_2 flowing through a leaky fault across a caprock, it is preferable to use gel-foams that have attractive stability properties.

The typical scenario envisaged is the injection of gel-foams below the caprock, as close as possible to the leaky fault in which CO_2 is flowing.

Gel foams will be studied in the laboratory. Due to their complexity, a feasibility study will first be performed, before optimizing some important aspects such gel strength, gelation time. Through numerical simulations, we will study the injection strategy and provide estimates of volumes needed for the desired distance of influence.

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