Measurement of trapped gas saturation in carbonate rock: comparing 2-phase and 3-phase data to support CCS and CO_2 EOR projects

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Abstract: This paper presents a comprehensive experimental study of trapped gas saturation (S_{gt}) using carbonate rocks, a crucial parameter for CO_2 storage (CCS) and gas-based Enhanced Oil Recovery (gEOR) processes. The study aimed to measure S_{gt} under different injection strategies, rock types, wettability, and injection sequences using limestone reservoir cores taken from two different reservoirs (B and G) and one saline aquifer. The experiments were conducted under both 2-phase and 3-phase flow conditions, using CO_2 as injection gases and water and oil as displacing fluids. The 3-phase experiments revealed that S_{gt} is strongly dependent on the order of fluid injection sequence, with a higher S_{gt} observed during WAG experiments starting with water injection (WAG_W) compared to those starting with gas injection (WAG_G). Furthermore, a significant difference in trapped gas saturation was observed between the cores from reservoir G and reservoir B, with higher S_{gt} observed for reservoir G despite having higher permeability. The study also found that trapped gas saturation increases as the initial water saturation increases in samples sinitialised at mobile water saturation to mimic the transition zone. Interestingly, trapped gas saturation measured in WAG_G experiments starting at mobile water saturation was higher than that measured in WAG_G experiments starting at connate water, despite the initial gas saturation being much higher in the latter. Moreover, trapped gas by saline brine was measured on core samples from reservoir G and saline aquifer to study the impact of different rock types. The results on core G showed that S_{gt} is much higher in 2-phase compared to 3-phase experiments. The 2-phase experiments showed that trapped CO_2 by water is higher than trapped CO_2 by oil. This study presents a comprehensive dataset that is vital for validating gas injection and storage models in commercial simulators. The results demonstrate that S_{gt} obtained in 2-phase flow experiments is not applicable to 3-phase flow conditions, and capillary trapped gas in CCS projects is much higher than trapped gas in CO2 EOR projects. The results also show that trapped gas saturation during WAG cannot be modelled using a simple trapping function that only correlates trapped gas with initial gas saturation.

Introduction

Trapped gas saturation in porous media is a key parameter that affects both CO_2 EOR and carbon capture and storage (CCS) projects. CO_2 EOR is a mature technology which has been applied either as continuous CO_2 injection or CO_2 WAG since the early 1970s. The number of CO_2 EOR projects are increasing with time, and it is expected to recover billions of barrels of crude oil in the next 20 to 30 years. In addition, a significant increase in the number of CCS projects has been observed in the last few years. CCS is a key enabler to reduce carbon emissions, recognised to play a key role in the journey to net zero, delivering low carbon energy and featuring prominently in many countries' climate action plans.

Capillary trapping of CO_2 in the pore space of porous media is a key process for carbon sequestration. This process is controlled by fluid and interfacial physics at the pore scale. The main parameters affect capillary trapping of gas are rock heterogeneity, initial gas saturation, rock wettability, etc. The rock wettability is important for CO_2 sequestration in depleted reservoirs and for gas trapping in gas based EOR such as water alternating gas (WAG), simultaneous injection of water and gas (SWAG), etc.

Extensive laboratory experiments have been performed in the literature to characterise the 2-phase flow of CO_2-brine and the trapped CO_2 saturation. A comprehensive review is presented by Al Mansoori 2009 [1] and Krevor et al., 2015 [2]. However, there is also lack of data to compare trapped gas in 2-phase and 3-phase and whether the data measured in 2-phase can be applied for 3-phase flow or vice versa. For CO_2 EOR, the presence of two more phases (oil and water) adds extra complication to the trapping mechanism as it is not clear how much gas is trapped in the presence of both oil and water for the possible displacement processes.

There is good understanding in the literature of capillary trapping mechanisms that take place within the pore space based on the experience of the oil and gas industry. Capillary trapping is a process that can be well constrained and measured in well-designed laboratory experiments and modelled using available models including capillary pressure and relative permeability hysteresis. It plays a key role in storage security, slowing plume migration, increasing storage capacity, and enhancing reservoir integrity [2].

Trapped gas saturation has been investigated in three-phase systems by many authors, see Caubit, et. al., 2004 [3], Kralik, et.al., 2000 [4], Kyte, et. al., 1956 [5], Skauge and Ottesen, 2002 [6]. The data is measured on consolidated core material and mainly sandstone. Oak et al. 1990 [7] investigated three-phase relative permeabilities in an intermediate-wet Berea sandstone, while Vizika and Lombard, 1996 [8] studied three-phase drainage for water-wet, oil-wet, and fractionally wet systems.

Extensive studies of three-phase flow in mixed-wet and oil-wet media was performed by Jerauld 1997 [9], who showed that the Land 1968 [10] model gave poor predictions for gas trapping in Prudhoe Bay cores. A new three phase relative permeability model was developed based on two-phase measurements for Prudhoe Bay that more accurately matched the experimental data.

For residual or trapped gas saturation, Kralik et al. [4], and Skauge and Ottesen [6] showed experimentally that the three-phase residual gas saturation is lower than the two-phase residual gas saturation. Maloney et al. [11] and Jerauld 1997 [9] instead suggested that the two- and three-phase residual gas saturation are equal. Caubit et. al., [3] also showed that the values of trapped gas saturation are independent of wettability and similar to the two-phase values.

In this paper, the focus is on the measurement of trapped CO_2 saturation in 2-phase and 3-phase experiments. In addition, the paper investigates the parameters that affect CO_2 trapping, such as saturation history, presence of mobile water, wettability, rock types, heterogeneity, etc. This work presented in this paper is a continuation of the work preented in Masalmeh et. al.,[12].

Core Materials and Fluids Properties

Reservoir Cores

Three reservoir cores (2 in. diameter) used in the coreflood experiments were obtained from carbonate reservoirs ‘B,’ (2 different core samples) and ‘G’ (one core sample). In addition, 2 more core samples were obtained from a saline aquifer. The reservoir cores were relatively high purity limestone typically containing less than 2% clay and 4% silica. The selected cores were uniform limestone with no visible fractures with adequate length to reduce the capillary end effects often seen in small core plugs. The properties of the core samples are listed in Table 1.

Table 1: Properties of cores B, G and S used in this work.

Properties	B1 Core	B2 Core	G Core	S1 Core	S2 Core
Diameter, cm	5.1	5.1	5.1	3.80	3.76
Length, cm	24.0	25.4	24.3	12.34	10.76
Porosity (Φ), %	18	19.50	29.95	31.6	27.0
Permeability to Brine (k), mD	0.8	1.8	16.2	4.9	33.5

To prepare the cores for the experiments, first, each of the reservoir cores was thoroughly cleaned with toluene and methanol injected in cycles before drying and weighing the core. Each core was then loaded in a high-pressure core holder and its pore volume (PV) was measured. Later, the cores were fully saturated with formation water (FW) and permeability measurements were performed.

Fluids

Two crude oils have been used in the 3-phase experiments, crude B and G. They were centrifuged to separate possible water content before injecting the crude oils into the core. The formation brines for the above-mentioned reservoirs were prepared volumetrically at atmospheric conditions, stirred and degassed before testing. The properties of the crude oils (B and G) used in the experiments and the minimum miscibility pressure (MMP) with CO2 are found in Masalmeh et. al. [13]. The compositionsof the three brines (B, G and S) are shown in Table 2.

Table 2: Formation brines compositions used in coreflood experiments on ‘B,’ and G reservoirs and the Saline Aquifer (S).

Salt Component (ppm)	B	G	S
NaCl	49898	48667	54010
CaCl2.6H20	14501	20792	15200
MgCl2.6H20	3248	1368	3490
Barium	0	0	0
Strontium	0	0	0
KCl	1990	0	1140
Na2SO4	234	373	345
NaHCO3	162	180	135
TDS	**179853**	**186747**	**195379**

Dead crude oils were mixed with the corresponding associated gas to make the recombined reservoir crude oils. The mixing process was performed at corresponding reservoir pressure and temperature of each reservoir. It was performed in a manner to match the reported GOR of the live recombined fluid for reservoir B. As for the reservoir G, the crude oil was saturated with methane to yield live oil.

Table 3 lists the results of PVT properties measured for both recombined live oils at reservoir conditions. Different gases have been used in the 3-phase experiments, CO_2, a mixture of 10% CH_4 and 90% CO_2 and 50% CH_4 and 50% CO_2 and HC gas. All the 2-phase experiments were performed using CO_2 as injected gas. The gas was always equilibrated with water in all experiments to reduce gas solubility in water. For the 2-phase oil-gas experiments, CO_2 was also equilibrated with the oil to minimise mass transfer. More details on the experimental procedure is provided in the subsequent sections on the experimental results.

Table 3: PVT properties of the recombined fluids (B, and G) used in these coreflood experiments.

Parameter	B	G
GOR (Scc gas/Scc oil)	160.22	127.15
Oil Viscosity (cP)	0.361	0.381
Water Viscosity (cP)	0.404	0.391
Formation volume factor (Rcc/Scc)	1.55	1.28
Bubble Point (psig)	2705	4800

Experimental Setup

The experimental setup used in these experiments has been described in earlier publications [12 and 13]. In the experiments reported here, the orientation of the core was vertical, and the overburden pressure was kept at 500 psig above the pore pressure (pressure at BPR).The core samples were first cleaned and saturated with 100% water. Brine permeability measurement was performed at room temperature and reservoir pressure.

All phases (oil, gas and brine) were pre-equilibrated with each other at the conditions of experiments to minimise the mass transfer during displacement. All fluids saturations within the cores were measured using the volumetric method. It is worthwhile to mention that the dead volumes of the system were kept very small to make the volumetric calculation accurate. Therefore, the error of the measurements is around 1.5 saturation unit.

The following types of experiments have been performed:

1- Two phase water-gas (CO_2) experiments.
2- Two phase oil-gas (CO_2) experiments in the presence of immobile connate water.
3- Three phase experiments starting at connate water of ~10% and live oil. Two types of WAG experiments were performed; WAG_G where the first injection cycle is gas and WAG_W where the first injection cycle is water.
4- Three phase experiments starting at mobile water saturation to mimic gas or WAG injection processes in transition zone and to study the impact of mobile water on trapped CO_2.

Please not that more details on the experimental procedure will be provided in the subsequent sections on describing the different experiemnst.

Experimental Procedure, Results and Discussion

Trapped Gas in Two Phase Measurement

Several experimental studies are available in the literature to investigate gas trapping in 2-phase water-gas or oil-gas and in 3-phase water-oil-gas systems. Most of the data published in the literature has been measured using sandstone rock. A summary of the literature data and the developed trapping models have been discussed in [1]. In this work, the experiments are performed using limestone core samples.

The application of the work is for CO_2 storage in saline aquifers where capillary trapping is a rapid and effective mechanism to render injected CO_2 immobile. For CO_2 storage in saline aquifer, the CO_2 is injected into the formation and once CO_2 injection is stopped, natural groundwater flow displaces and traps CO_2 in the pore space as a residual immobile phase.

Trapped Gas in Water-Gas 2-Phase Corefloods

Several 2-phase water-CO_2 experiments were performed to obtain trapped gas saturation by water as a function of initial gas saturation. The experiments were performed using 3 different core samples where one sample from reservoir G and 2 samples from a saline aquifer, reservoir S. The properties of the samples are shown in Table 1. Note that in all experiments, the initialization at the target initial water saturation was performed by either gas injection or oil injection. The other techniques such as centrifuge or porous plate could not be used due to the dimensions of the core samples and the use of live fluids in all experiments.

Two different procedures were followed:

1- First procedure:
   a. The core sample is saturated at 100% water.
   b. Gas displaces water to initial gas saturation S_{gi}
   c. Water displaces gas to measure trapped gas saturation.
   d. The core sample is saturated again at 100% water and another experiment is performed targeting a different S_{gi}.
   e. The same procedure is repeated to measure 3 or 4 different S_{gi}-S_{gt} points.
2- Second procedure:
   a. The sample is saturated at 100% water.
   b. Gas displaces water to S_{gi1}
   c. Water injection to measure S_{gt1}.
   d. Gas is injected again to S_{gi2}, which is higher than S_{gi1}
   e. Water injection to measure S_{gt2}
   f. The same procedure is repeated to measure S_{gt} at higher S_{gi}

Figure 1 shows the trapped gas saturation measured by performing multiple injection cycles starting from the lowest Sgi. Note that in subsequent cycles, gas injection rate was increased significantly to target higher initial gas saturation. However, due to the adverse mobility ratio and the capillary end effect, the maximum achieved initial gas saturation is around 55%.

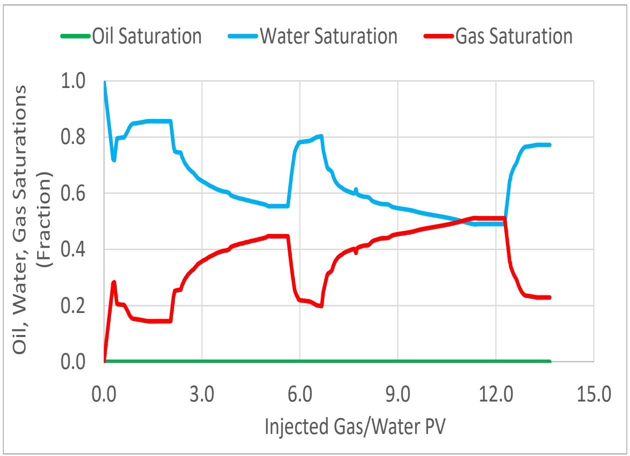


Figure 1: Water and gas saturation for different cycles of water and gas injection targeting different S_{gi} in each cycle using core G.

Note that gas displacing water experiments suffer from experimental artefacts such as viscous fingering due to adverse mobility ratio and capillary end effect as water is the strongly wetting phase. To reduce the capillary end effect, the experiments were performed using long core of 10 to 20 cm long. Gas injection was also performed from top to ensure gravity stable displacement.

Due to these experimental artefacts, obtaining S_{gi}-S_{gt} data over a wide saturation range using subsequent gas and water injection experiments is challenging. It is difficult to achieve high initial gas saturation during the drainage experiment due to the combination of viscous fingering and capillary end effect. Increasing the gas injection rate to overcome capillary end effect does not lead to significant increase in gas saturation due to the well-established paths (fingers) at low rates. Therefore, upon increasing the injection rate, the gas will still mainly flow through the existing paths (gas fingers) which leaves behind high mobile water saturation. Therefore, the following procedure was performed to obtain high gas saturation:

1- For core G, the sample was initialised at connate water and Sgi~87%. This high saturation was achieved by
   a. Oil displacing water to Swc of 13%.
   b. Oil displaced by different miscible solvents and last step was CO_2 injection.
   c. Water displaced gas to measure S_{gt}
2- For core S2: the sample is initialised at 100% CO_2 and then water displaced gas to measure maximum S_{gt}.

Note that, the gas distribution at the start of water injection in these experiments is significantly different compared to those sinitialised by gas injection. The gas saturation profile is uniform for the samples initialised at connate water or at 100% CO_2 saturation. However, for those initialised by CO_2 injection into 100% water saturated sample, the saturation profile is not uniform due to viscous fingering and capillary end effect discussed above.

Figures 2 and 3 show the S_{gi}-S_{gt} data measured on the 3 different samples following the procedures outlined above. Figure 2 shows the data measured on sample G and figure 3 shows the data measured on samples S1 and S2. In addition the S_{gi}-S_{gt} correlation that best represents the data is also shown in the figures.

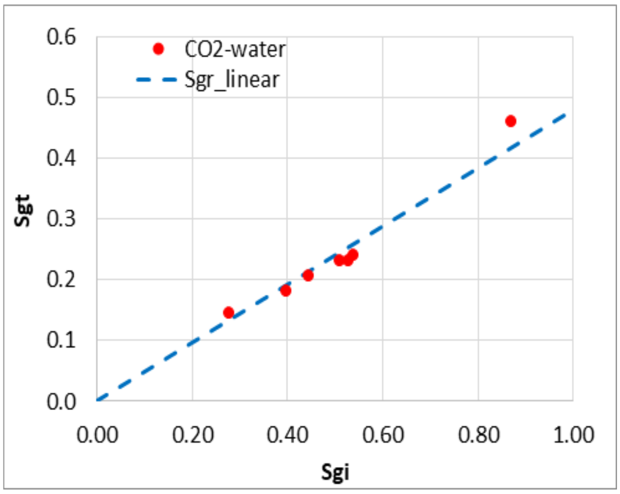


Figure 2: Initial gas and trapped gas saturation correlation for CO_2 water-gas system measured using core G.

The data shows the following:

1- For core G, S_{gt} increases linearly with S_{gi} irrespective of the procedure followed to obtain the initial gas saturation. The maximum S_{gi} obtained by gas injection is 55%.
2- For core samples S1 and S2, S_{gi}-S_{gt} followed land correlation with land parameter of 2.3. Note that the maximum initial gas achieved by gas injection is 70%.
3- Comparing the data measured on core G with the data on cores S1 and S2:
   a. S_{gt} measured on core G is lower up to S_{gi} of 50%.
   b. S_{gt} measured on core G increases significantly for the higher S_{gi}, however, there is no data points in the range of S_{gi} between 55 to 87%.

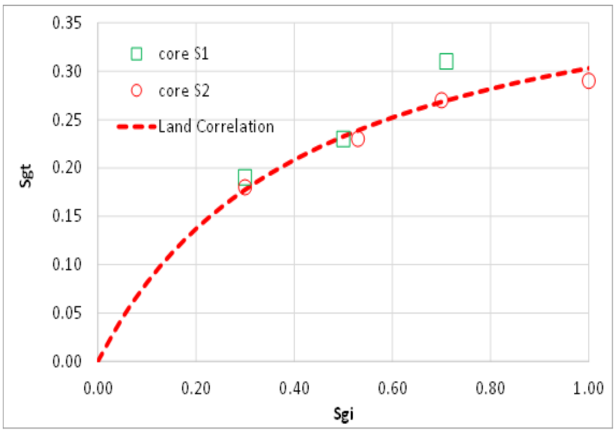


Figure 3: Initial gas and trapped gas saturation correlation for CO_2 water-gas system measured using cores S1 and S2.

Trapped Gas in 2-Phase Oil-Gas Coreflood using Equilibrated CO_2

In this section, trapped gas saturation by oil is measured and compared with trapped gas by water. The application of this work is for gas based EOR, especially WAG or SWAG processes. For most three phase relative permeability models, that are used to model 3-phase flow, trapped gas saturation is provided in the gas-oil relative permeability curves. The assumption is that the trapped gas saturation during the water injection cycles is the same as the trapped gas provided in the gas-oil relative permeability curves. However, very few studies are available in the literature to compare trapped gas saturation by oil and water to confirm such assumption. Jerauld [14] concluded that trapped gas is independent of the oil or liquid phase.

The experimental procedure to measure trapped gas by oil (using equilibrated CO_2 with oil) is:

1. Initialise the sample at S_{wc} (~10%) and restore wettability by aging the sample for 4 weeks
2. Displace oil by CO_2 up to 20% gas saturation. Inject gas at a low rate, from top to bottom to ensure gravity stable displacement.
3. Displace gas (CO_2) by oil to measure trapped gas saturation.
4. Displace oil by CO_2 up to 40% gas saturation. Inject gas at a low rate, from top to bottom to ensure gravity stable displacement.
5. Displace gas (CO_2) by oil to measure trapped gas saturation.
6. Repeat the same injection cycles targeting higher initial gas saturation and then measure subsequent trapped gas saturation.

Note that the gas-oil experiments are performed at connate water. Even though the water is immobile during these experiments, however; the presence of the third phase could affect the trapped gas saturation as the wettability could be different in the presence of 3 phases compared to 2 phases. The 2-phase gas-oil experiments are performed using core G only.

The gas-oil S_{gi}-S_{gr} correlation measured at connate water is shown in Figure 4. The figure also shows the gas-water data measured on the same core and presented in figure 2 above. The maximum initial gas saturation achieved by gas injection is 72%, which is 17% higher than that achieved during gas-water experiments. This shows the CO_2-oil displacement is more stable than the CO_2-water displacement. This is due to lower viscosity difference and weaker capillary end effect (lower IFT). Hence, for the CO_2-water experiments, more viscous fingering is expected compared to CO_2-oil experiments which may lead to higher trapped gas by water Even though n both cases, gas is the non-wetting phase. However, during the 2-phase water-gas experiment, water is strongly wetting, and capillary snap off will lead to high trapped gas. On the other hand, during the oil-gas displacement the presence of connate water affects the wetting nature of the rock and may reduce the effect of snap off and leads to lower trapped gas. Therefore, data shown in figure 4 demonstrates that trapped gas measured by oil could be significantly lower than that by water and the data measured in gas-oil system is not representative for water-gas system.

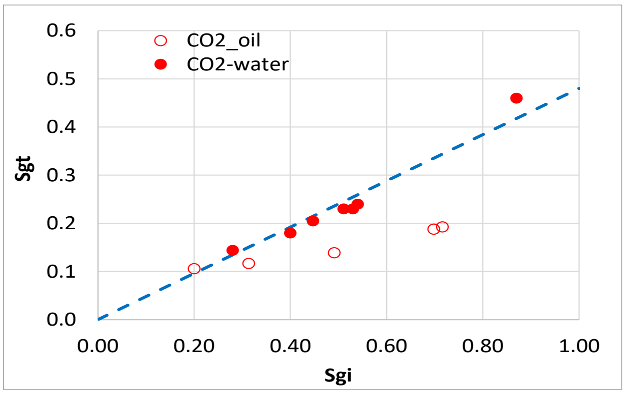


Figure 4: Initial gas and trapped gas saturation correlation for oil-gas system at connate water using core G compared with water-gas data measured on the same sample.

This conclusion shows that the assumption in the 3-phase relative permeability models that the trapped gas saturation is independent of the trapping phase is not generally valid. A more general trapping model is needed that can distinguish between the trapped gas by water or oil.

In summary, the 2-phase data show that trapped gas is dependent on the rock type and on the trapping fluid. The impact of both parameters is significant as the difference in trapped gas could be more than 15 saturation units for different rocks or for different trapping fluid as shown in Figures 2-4.

Three-Phase Measurements of Trapped Gas Saturation

Trapped gas saturation has been measured under 3-phase conditions. The experiments were performed using live crude oil, synthetic formation water and different gases.

In all the experiments the injected gas was equilibrated with water to minimise solubility of the gas in the aqueous phase during the experiment. The objectives of these experiments are to:

1- Compare gas trapping in 2-phase and 3-phase experiments and investigate whether the data measured under 2-phase conditions can be used in modelling gas injection under 3-phase conditions.
2- Compare trapped gas in WAG_G and WAG_W experiments.
3- Investigate the impact of the presence of mobile water saturation on trapped gas.
4- Impact of the gas type on trapped gas saturation.
5- Investigate the effect of wettability on trapped gas saturation.
6- Impact of rock type on trapped gas saturation

The application of these measurements is for gas-based EOR, to calculate how much CO_2 is trapped in the reservoir at the end of CO_2-WAG injection projects and for CO_2 storage in depleted oil reservoirs.

Several WAG experiments have been performed with different cycles of water and gas injection. Moreover, the experiments have been performed using different gases: 1- CO_2, 2-Mixture of 50%CH_4 and 50%CO_2, 3- Mixture of 10% CH_4 and 90% CO_2 and 4- Miscible HC gas. The subsequent sections will present trapped gas saturation measured in the following experiments:

1- 3-Phase experiments initialised at connate water of ~10% and the first cycle is gas injection (WAG_G)
2- 3-phase experiments initialised at connate water of ~10% and the first injection cycle is water followed by gas and water injection (WAG_W)
3- 3-phase experiments initialised at mobile water where S_{wi} is 0.4 and 0.6. In this case, gas injection starts at high water saturation, irrespective if the experiment starts with gas or water injection. These experiments represents WAG in transition zone reservoirs and (WAG_G_TZ or WAG_W_TZ).

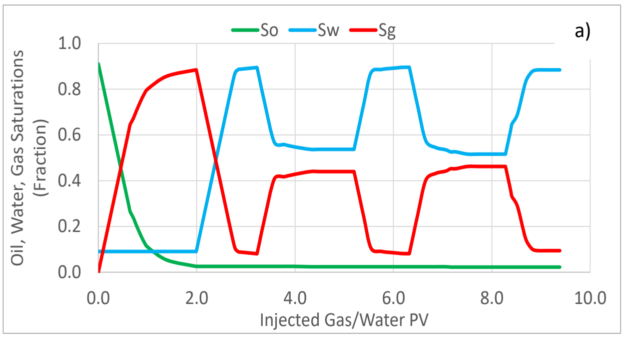
Trapped Gas Saturation During WAG_G and WAG_W Experiments

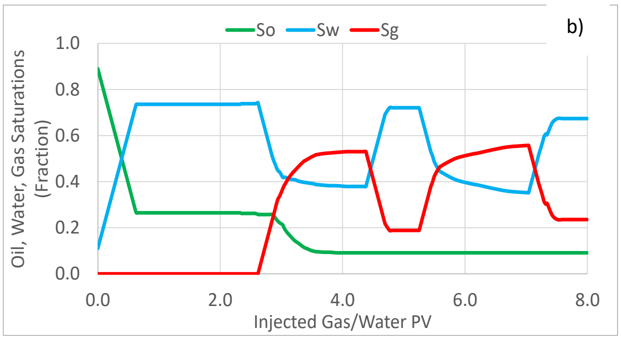
Two different types of WAG experiments were performed, WAG starting with gas injection (WAG_G) and WAG starting with water injection (WAG_W). The core sample B2 is initialised at connate water of 9% and aged for four weeks to restore wettability. The data of both experiments are shown in Figures 5a (WAG_G) and 5b (WAG_W). As shown in Figure 5a, during the first gas injection cycle, gas displaces only oil as the water is immobile. At the end of gas injection cycle, the gas, oil and water saturations are 88%, 3% and 9%, respectively. The wetting order of the fluids is that oil is the wetting phase, gas is the non-wetting phase and water is the intermediate wetting phase. During the first water injection cycle, water displaces gas as the only mobile phase. The water-gas displacement is stable due to favorable mobility ratio and trapped gas is 8%.

In the subsequent WAG cycles, the trapped gas saturation remains the same (~ 8%) though the initial gas saturation was much lower, S_{gi} ~ 45%. The second gas injection cycle displaces only water, the displacement is unstable due to the adverse mobility ratio which leads to high mobile water saturation. The gas saturation at the end of the gas injection cycle is divided into 2 parts, a connected mobile gas and an immobile trapped gas which is trapped in the part of the core that was not accessed by the injected gas. Therefore, the total trapped gas at the end of the second water injection cycle remains the same as the first cycle. This is observed in the third cycle and in all the other experiments performed with the other gases. This demonstrates that trapped gas saturation depends on both the initial gas saturation and the history of the gas saturation in the porous media in earlier injection cycles. Therefore, trapped gas saturation during WAG cannot be modeled using a simple trapping function that only correlates trapped gas with initial gas saturation.

Figure 5b shows different injection cycles of WAG_W experiment which was performed using the same core sample B1 and initialised at the same connate water of 9%. At the end of the first water injection cycle, water and oil saturations are 74% and 26%, respectively. As shown in the figure, during the first gas injection cycle, gas displaces mainly water, and it also reduces residual oil from 26% to 9%. Due to the unstable gas-water displacement, the gas saturation at the end of the gas injection cycle is 53% and water saturation is 38%. Trapped gas saturation during the subsequent water injection cycle is 19%. Note that the trapped gas saturation is a factor of 2 higher than S_{gt} in the WAG_G experiment even though the S_{gi} is much lower, i.e., 53% compared to 88%. The data shows that the presence of mobile water during the gas injection cycle has a significant impact on S_{gi} and gas distribution. This has also significant impact on S_{gt} in the subsequent water injection cycle. The CO_2 injection that starts at connate water is a miscible displacement of oil and hence it is more stable. However, during the WAG_W experiment, gas is mainly displacing water and the displacement is unstable due to the experimental artefacts discussed above which leads to lower initial gas saturation and viscous fingering.

Comparing the results of the two experiments (WAG_G and WAG_W) demonstrates that trapped gas saturation in 3-phase flow in porous medium cannot be described by simple trapping functions where trapped gas is only dependent on initial gas saturation.





Figures 5: Oil, water and gas saturation during different cycles of CO2 WAG experiments using core B2, a) WAG_G experiment and b) WAG_W experiment.

Table 4: List of experiments to measure Sg-Sgt data using cores B1, B2 and G

Experiment	Sgi	Sgt	Core
WAG_G CO2	0.85	0.09	B1
WAG_G_CO2	0.88	0.08	B2
WAG_G_50%C1_50%CO2	0.78	0.11	B2
WAG_G_10%C1_90%CO2	0.81	0.09	B2
WAG_G_HC gas	0.78	0.08	B2
WAG_W_CO2	0.53	0.19	B2
WAG_W_50%C1_50%CO2	0.52	0.14	B2
WAG_W_10%C1_90%CO2	0.5	0.14	B2
WAG_W_HC gas	0.53	0.11	B2
WAG_G_CO2	0.75	0.14	G
WAG_W_CO2	0.62	0.36	G

Similar experiments were performed using the same core, oil and water but different injected gases, i.e., 10%CH_4 + 90%CO_2, 50%CH_4 + 50%CO_2 and HC gas. One more experiment of CO_2-WAG starting with gas was performed on core B1 and two more CO_2-WAG experiments (WAG_G and WAG_W) were performed using core sample and fluids from reservoir G. The type of experiments and the measured S_{gi}-S_{gt} data are shown in Figure 6 and Table 4. The data show that:

1- Much higher S_{gi} is achieved during the WAG_G experiments (75 to 88%) and lower S_{gt} (8 to 14%) compared to WAG_W experiments where S_{gi} is 50% to 62% and S_{gt} is 15% to 36%.

2- The experiments performed on core G showed higher trapped gas, especially the WAG_W experiment, compared to those on cores B1 and B2 even though core G has higher permeability. This could be due to the heterogeneity of core G compared to core B2, as shown in Figure 7.

3- There is no correlation between the type of the gas used in the 4 WAG_G experiments performed on core B2 and the trapped gas saturation, it only increases from 8 to 11%.

4- There is a weak correlation between gas type and S_{gt} during the WAG_W experiments as S_{gt} increased from 11% to 19% during the 4 experiments performed on core B2, where CO_2-WAG had the highest and the HC gas WAG had the lowest S_{gt}.

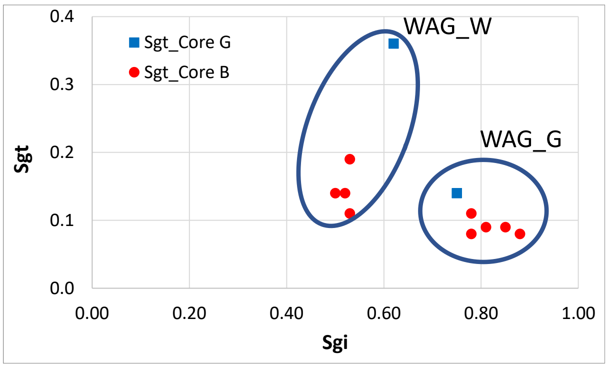


Figure 6: Initial gas and trapped gas saturation measured in different CO2 WAG experiments (WAG_G and WAG_W) performed on core samples from reservoir B2 and G.

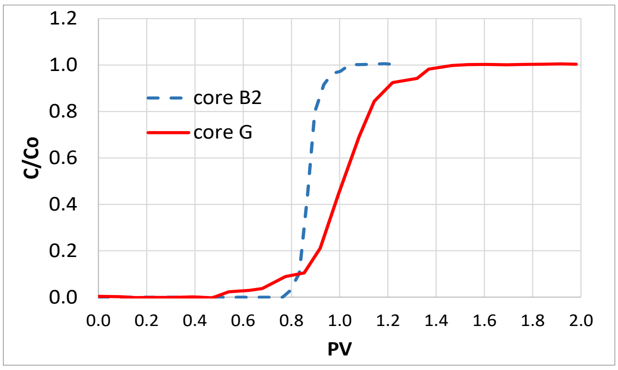


Figure 7: Profile of the dimensionless concentration of tracer versus tracer pore volumes injected for cores B2 and G.

Trapped Gas Saturation in 2 Phase and 3 Phase Experiments

Figure 8 shows trapped gas saturation measured in 4 different experiments using core G. The data of the 4 experiments has been discussed in the previous sections:

1- 2-phase water-gas starting at Sgi=87% and Swc=13%

2- 2-phase oil-gas stating at Swc=10%, So=18% and Sgi=72%. In this experiment oil displaces gas in presence of connate water.

3- 3-phase WAG_G experiment where water injection starts at Swc=12%, So=13 and Sgi=75%. In this experiment, water displaced gas in the presence of residual oil saturation.
4- 3-phase WAG_W experiment where water injection started at Sw=26%, So=11% and Sgi=63%.

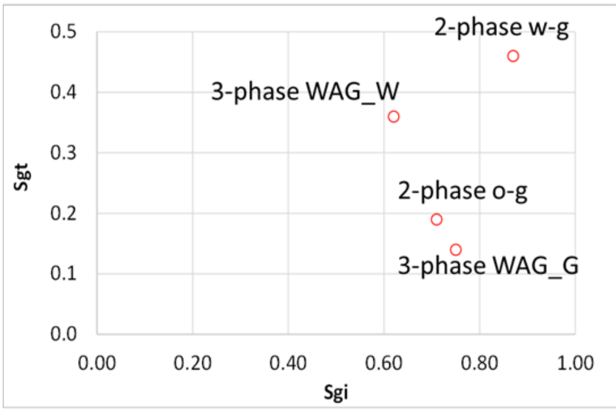


Figure 8: Initial gas and trapped gas saturation measured in 4 different experiments on core G to compare 2-phase and 3-phase gas trapping.

As shown in the figure, the highest trapped gas is measured during the 2-phase water-gas (46%) followed by 3-phase WAG_W experiment (36%). However, those 2 points seem to follow the same linear correlation. The trapped gas measured during the 2-phase oil-gas and the 3-phase WAG_G experiment are the lowest, 19% and 14% respectively.

Comparing the 2-phase water-gas experiment with 3-phase WAG_G experiment shows that the presence of oil and wettability significantly affects trapping mechanisms. In the 3-phase experiments, the sample is weakly oil-wet, while in 2-phase water-gas experiments the sample is strongly water-wet. Therefore, for the strongly water-wet case, there is significant snap-off of gas by water and that leads to much higher trapped gas. On the other hand, for the 3-phase WAG_G experiments, the water is non-wetting to oil and that significantly reduces the snap-off mechanism and leads to much lower trapped gas. The same reason explains the low trapped gas saturation during the 2-phase oil-gas experiment, i.e., snap-off is reduced during the oil displacing gas experiment. The high trapped gas measured during the WAG_W experiment is discussed above in earlier section; it is due to the distribution of gas at the end of gas injection cycle in the presence of mobile water.

For the WAG_G experiment shown in Figure 5a performed on core B2, the trapped gas saturation is 8% for an initial gas of 88%. In this experiment the residual oil was only 3% but still due to non-water-wet nature of the core, the trapped gas saturation is significantly lower than expected for water-wet core. This demonstrates that trapped gas saturation by water in WAG_G experiments is much lower than that in 2-phase water-gas experiments.

Effect of Initial Mobile Water Saturation on Trapped Gas

A number of experiments have been performed where the core sample was initialised at mobile water saturation, i.e., both oil and water are mobile to mimic gas, water or WAG injection in transition zone oil reservoir. The core samples were saturated with 100% water, then oil displaced water (using steady state experiment) to different initial water saturation, mainly to 40% and 60%. To investigate the impact of initial water for a wide range of saturation, 2 more experiments were performed at Swi ~10% and 80%, respectively. The experiments have been performed using core B1. In general, the data showed that the higher the initial water saturation the higher the trapped gas saturation in the subsequent gas and water injection cycles.

An example is shown in Figure 9, where the sample was initialised at 40% and 60% water saturation, respectively. Figures 9a & b show the data of WAG_G experiments and Figures 9c & d show the data of WAG_W experiments, respectively. The data show the following:

1. For WAG_G experiments: The gas saturation at the end of the first gas injection cycle is 52% in both cases while the trapped gas saturation is 14% and 19% for the cases of S_{wi} 40% and 60%, respectively.
2. For WAG_W experiments: The gas saturation at the end of the first gas injection cycle is ~55% in both cases while the trapped gas saturation is 20% and 26% for the cases of S_{wi} 40% and 60%, respectively.
3. In line with the earlier data performed starting at connate water and shown in Figure 8 and Table 4, the trapped gas saturation for the WAG_W experiments is higher than that measured in the WAG_G experiments:
   a. For S_{wi}=40%, Sgt is 14% for WAG_G and 20% for WAG_W.
   b. For S_{wi}=60%, Sgt is 19% for WAG_G and 26% for WAG_W.
4. Trapped gas saturation measured in WAG_G experiments starting at mobile water (Figure 9a & b) is much higher than that measured in experiments starting at connate water using either core B1 or B2, see Figures 5a and 6 and Table 3. This demonstrates that the presence of mobile water, either in transition zone (occupies the smaller pores) or at the end of water injection (occupies the larger pores) leads to higher trapped gas saturation.

The same experiments (WAG_G and WAG_W) were performed on the same core sample (core B1) using CO2 equilibrated with crude oil to sminimise mass transfer between oil and CO2 during the gas injection cycle. The results showed the same conclusion where trapping during WAG_G experiment is lower compared to WAG_W when performed at the same Swi and trapped gas increases with increasing initial water saturation.

The data presented in Figure 9 confirms that gas trapping cannot be described by simple trapping function that correlates trapped gas with initial gas saturation only.

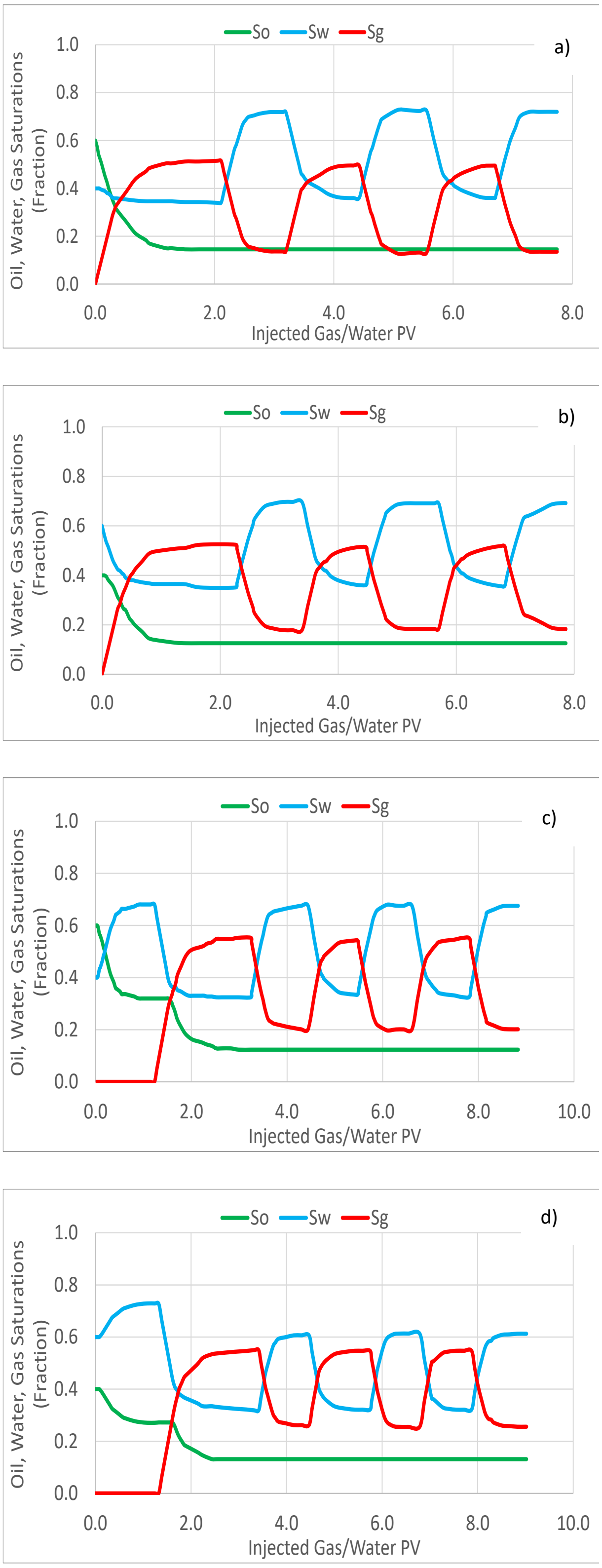


Figure 9: Oil, water and gas saturation during different cycles of CO2 WAG experiments performed on core B starting at different Swi, a) WAG_G experiment at Swi=40%, b) WAG_G experiment at Swi=60%, c) WAG_W experiment at Swi=40% and b) WAG_W experiment at Swi=60%.

Effect of fluid distribution and pore occupancy on trapped gas

So far, the discussion has focused on the impact of mobile water on the trapped gas saturation. In this section the impact of fluid distribution and pore occupancy on trapped gas will be discussed. We will compare WAG_W starting at connate water with WAG_W and WAG_G starting at Swi=60%.

The data of the 3 experiments are shown in Figures 5b, 9b and 9d. During WAG_W experiment starting at connate water of 10%, water displaces oil from the large pores as the sample is non-water wet. At the end of the cycle, the water saturation is 74%, where connate water occupies the smallest pores and the other 64% occupies the big pores. During the subsequent gas injection cycle, gas will mainly displace water from the large pores and reduce residual oil from 26% to 9%. Therefore, trapped gas in the subsequent water injection cycle will mainly be trapped in the big pores.

During WAG_W experiments starting at Swi=60%, water displaces oil from the large pores. As shown in Figure 9d, S_{orw} is 27% and therefore water occupies mainly the smaller 60% of the pores and only 13% occupies the large pores together with the trapped oil. During the gas injection cycle, gas will partly displace oil as S_{orw} is reduced to 13% and will mainly displace water which occupies the smaller pores. Compared to the WAG_W experiments starting at connate water, gas will occupy more small pores and hence, higher trapped gas is expected. This is indeed what is measured as Sgt is 26% compared to 19%, see Figures 5b and 9d.

For WAG_G experiment starting at Swi=60%, at the start of the gas injection cycle, water occupies the smaller 60% of the pores while oil occupies the largest 40% of the pores. During the gas injection cycle, gas will start displacing oil from the larger pores and water from the larger pores occupied by water. At the end of the cycle, 27% of the gas occupies the larger pores where it displaced oil from and the rest occupies the largest of the water filled pores. This means that the gas distribution at the beginning of the subsequent water injection cycle is similar to that of the WAG_W starting at connate water. Therefore, similar value of trapped gas is expected which explains the measured value of S_{gt} 18-19% in both experiments, see Figures 5b and 9b.

Several experiments have been performed starting at different S_{wi}. The measured S_{gi}-S_{gt} data is shown in Figure 10, S_{gt} varies between 14% to 26% while Sgi and Sw are similar at the start of the water injection cycle. The main parameter that affects the trapped gas saturation is the gas distribution and pore occupancy at the start of the water injection cycle. The more gas occupies smaller pores the higher the trapped gas saturation. In addition, the higher the water saturation at the beginning of the gas injection cycle, the higher the trapped gas saturation in the subsequent water cycle as the higher water saturation leads to more viscous fingering and hence more gas is trapped in the subsequent water cycle.

The figure also shows the results of WAG_G experiments both at connate water and at high water saturation. As discussed above, S_{gt} in WAG_G experiments is lower than S_{gt} in WAG_W experiments. The lowest S_{gt} is measured at the highest S_{gi} where no mobile water was present during the gas injection cycle of at the start of the water injection cycle.

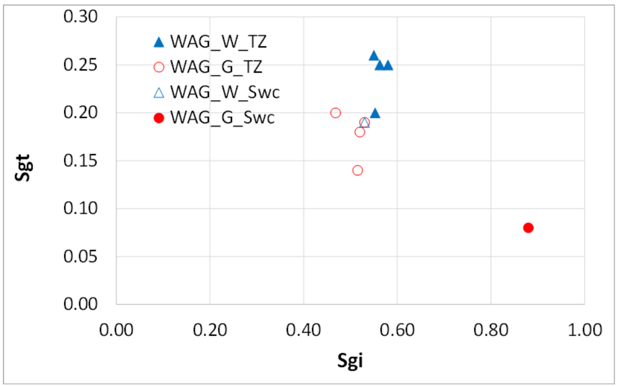


Figure 10: Sgi-Sgt data measured in different WAG_W and WAG_G experiments starting at different Swi, where the legend that includes Swc means experiments started at connate water and legends include TZ means experiments started at mobile water.

Based on the discussion above, trapped gas saturation is dependent on:

1- Initial water saturation at the beginning of the gas injection cycle: the higher the water saturation at the beginning of the gas injection leads to more viscous fingering and higher the trapped gas saturation in the subsequent water injection cycle.
2- The gas saturation distribution and the pore occupancy of the gas: the more gas in the smaller pores the higher trapped gas saturation.
3- The history of the gas saturation in the porous media: trapped gas saturation does not correlate with initial gas saturation in the subsequent cycles if the gas saturation at the end of the first cycle was higher than subsequent cycles.
4- Wettability of the rock: The presence of a third phase and the fact that the displacing phase is not-strongly wetting, reduces the trapped gas saturation.
5- Rock type: The data presented in Figures 6 show that 3-phase trapped gas strongly depends on the rock when comparing the data measured on core B2 and G. Moreover, the 2-phase Sgt-Sgi correlation measured on core G is different than those measured on cores S1 and S2 as shown in Figures 2 and 3.
6- The trapping phase: trapped gas by oil was much lower than trapped gas by water as shown in Figure 4.

Conclusions

A systematic study was performed to investigate trapped gas saturation in 2-phase and 3-phase flooding experiments using limestone reservoir cores from two different oil reservoirs, B and G and saline aquifer reservoir S. The experiments were performed under different injection strategies and investigated the impact of rock type, wettability, fluid injection sequence and presence of mobile water. The study was performed using different gases such as CO2, a mixture of C1 and CO2 and HC gas and investigated the impact of the type of displacing fluid (water or oil) on trapped gas saturation.

The main conclusions of the study are:

1- Trapped gas saturation depends on several parameters such as, Swi at the beginning of gas injection cycle, gas distribution and pore occupancy, history of the gas saturation in the porous media, wettability, presence of third phase, rock type and trapping phase.
2- Due to the complicated nature of S_{gi}-S_{gt} data, trapped gas saturation during WAG cannot be modeled using a simple trapping function that only correlates trapped gas with initial gas saturation.
3- The 2-phase water-gas experiments showed that trapped CO_2 can be as high as ~50%. This shows that capillary trapping of CO_2 during CCS projects is of significant importance.
4- In 2-phase water-gas and oil-gas experiments, trapped CO_2 by water is higher than trapped CO_2 by oil. The difference can be more than 15 to 20 saturation units.
5- The results of the 2-phase water-gas experiments performed on cores G, S1 and S2 showed that S_{gt}-S_{gi} on core G has a linear correlation while that on cores S1 and S2 follows Land correlation where Land parameter is 2.3.
6- In 3-phase experiments, trapped gas saturation is strongly dependent on the order of fluid injection sequence. S_{gt} is much higher during WAG experiments starting with water injection (WAG_W) compared to WAG experiments starting with gas injection (WAG_G). The same conclusion was confirmed based on the data measured on core samples from both reservoirs B and G.
5- Both 2-phase and 3-phase data showed that the results are strongly dependent on the rock type.
   a. 3-phase data show a significant difference between the trapped gas measured using core sample from reservoirs B and G.
   b. 2-phase data show a clear difference between trapped gas measured using core G compared to core S1 and S2, especially at high S_{gi}.
6- Trapped gas saturation by water measured in 2-phase water-gas experiments is much higher than that measured in 3-phase WAG_G experiments.
7- S_{gt} measured in 2-phase water-gas is similar to trapped gas in WAG_W experiments. This was only investigated using core G. No 2-phase data is available on core B, hence the conclusion cannot be generalised.
8- The presence of oil during the water displacing gas experiments (WAG_G) had a significant impact on trapping mechanism, especially the case where water cycle started at high S_{gi} and connate water.
9- Wettability of the rock has significant impact on trapped gas saturation. This is evident when

comparing 2-phase water-gas to 3-phase WAG_G experiments.

The study demonstrated that trapped gas measured in 2-phase experiments is not necessarily applicable to 3-phase flow. The results also show that the sequence of fluid injection can impact the amount of trapped gas. CO_2 WAG projects can be designed to minimise CO_2 sutilisation factor by starting with gas injection, or to smaximise CO_2 sequestration by starting with water injection.

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